United States Environmental Protection Agency

Small Entity Compliance Guide

for

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

40 CFR Part 60, Subpart OOOOa

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for
Oil and Natural Gas Sector: Emission Standards for New, Reconstructed,
and Modified Sources
40 CFR Part 60 Subpart OOOOa

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Notice

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The statements in this document are intended solely to aid regulated entities in complying with the published national regulation "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources". The final rule was published on June 3, 2016, in **Volume 81 of the Federal Register, page 38524 (81 FR 38524)** for Title 40 of the Code of Federal Regulations (40 CFR) Part 60, Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.

The U.S. Environmental Protection Agency (EPA) may decide to revise this guide without public notice to reflect changes in the EPA's approach to implementing the rule's requirements or to clarify and update text. To determine whether the EPA has revised this guide and/or to obtain copies, contact Lisa Thompson at (919) 541-9775, **thompson.lisa@epa.gov** or Amy Hambrick at (919) 541-0964, **hambrick.amy@epa.gov**.

The full text of the rule is available online at:
https://www.federalregister.gov/articles/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources

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1.0 Introduction to the Rule and this Compliance Guide

This document was published by the EPA as a compliance guide for small entities subject to the Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015, subpart OOOOa as required by the SBREFA. Before you begin using the guide, keep in mind that the information in this guide was compiled and published in August of 2016. The EPA is continually improving and updating its rules, policies, compliance programs, and outreach efforts. You can determine whether EPA has revised or supplemented the information in this guide by checking the Oil and Natural Gas Sector program web page for the rule, compliance requirements, and technical and related information (**https://www3.epa.gov/airquality/oilandgas/index.html**).

The final Oil and Natural Gas Sector New Source Performance Standards (NSPS) – called simply "the rule" in this document – was signed by the EPA Administrator on May 12, 2016, and published in the Federal Register on June 3, 2016. The rule's effective date is August 2, 2016, to allow 60 days for Congressional review after publication in the Federal Register. On this effective date, the rule's requirements become law. The information in this guide was compiled in order to assist those entities subject to the rule to understand better its requirements.

1.1 What environmental/human health issue(s) does this rule address and why it is important?

The final requirements include standards for greenhouse gas (GHG) emissions (in the form of limitations on methane) and standards for volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions. Methane is a GHG that traps heat in the atmosphere, which leads to climate change. Recent scientific assessments confirm and strengthen the conclusion that GHG emissions endanger public health, now and in the future. Studies indicate 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.''[1] The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis.

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. Methane is also a precursor to ground level ozone, a health-harmful air pollutant. Ozone is a short-lived climate forcer that contributes to global warming. Tropospheric, or ground level, ozone is also formed through reactions of VOC and nitrogen oxides (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. In remote areas, methane is a dominant precursor to tropospheric ozone formation.

[1] More information on these studies is described at 81 FR 35834.

1.2 What does the regulation require?

The Clean Air Act (CAA) requires the EPA to set NSPS for industrial categories that cause, or significantly contribute to, air pollution that may endanger public health or welfare. The rule establishes emission control standards for the oil and natural gas source category for GHGs (represented as methane), SO_2 and VOCs, which are significant pollutants with respect to climate change, national air pollution and human health issues. Oil and natural gas operations one of the largest emitters of GHGs in the U.S. (when considering both methane emissions and combustion-related GHG emissions at oil and gas facilities). The standards apply across a variety of emission sources in the oil and natural gas source category (i.e., production, processing, transmission and storage). Although the oil and natural gas industry is primarily known to be rural, emissions are also found to occur in or near populated areas across the country, due to recent increases in development of wells and facilities.

This rule applies to sources that are constructed, modified or reconstructed after September 18, 2015 and reflects today's technology, referred to as best system of emission reduction (BSER), considering costs. This guide addresses the requirements of subpart OOOOa in particular, and includes the same requirements that apply to sources that are subject to subpart OOOO. Therefore, if you are in compliance with the requirements outlined here for subpart OOOOa, then you are considered to be in compliance with subpart OOOO.

The rule achieves several objectives for oil and natural gas sector sources including addressing additional sources and applying updated emission control requirements that reflect the current BSER.

Table 1-1 summarizes these affected facilities (sources covered) by the rule and the final standards for GHGs and VOC emissions.

Table 1-1. Summary Final Subpart OOOOa Control Requirements

Affected Facility (Emission Source)	Final Subpart OOOOa Control Requirements
Well Completions: Non-wildcat and non-delineation wells.	• Reduced emissions completion (REC) in combination with a completion combustion device; venting in lieu of combustion where combustion would present safety hazards. • Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. • Separation flowback stage: Route all salable 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 onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. • The operator is required to have a separator onsite during the entire flowback period.
Well Completions: wildcat and delineation wells and low pressure wells.	• The operator is not required to have a separator onsite. • Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. • Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device with a continuous pilot flame. • For both options (1) and (2), combustion is not required 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.
Wet seal centrifugal compressors (except for those located at well sites)	95 percent reduction.
Reciprocating compressors (except for those located at well sites).	Replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure.
Pneumatic controllers (at natural gas processing plants)	Zero natural gas bleed rate.
Pneumatic controllers (at locations other than natural gas processing plants)	Natural gas bleed rate no greater than 6 standard cubic feet per hour (scfh).
Pneumatic pumps	Zero natural gas emissions.

Affected Facility (Emission Source)	Final Subpart OOOOa Control Requirements
(at natural gas processing plants)	
Pneumatic pumps (at well sites)	• 95 percent control if there is an existing control or process on site. • 95 percent control not required if; - Emissions are routed to an existing control that achieves less than 95 percent or - It is technically infeasible to route emissions to the existing control device or process (non-greenfield sites only).
Fugitive emissions from well sites and compressor stations.	Monitoring and repair of fugitive emission components using optical gas imaging (OGI) with Method 21 as an alternative at 500 parts per million (ppm).
Equipment leaks at onshore natural gas processing plants	Leak detection and repair (LDAR) program reflecting the leak definitions and monitoring frequencies established for 40 CFR part 60, subpart VVa.
Sweetening units at onshore natural gas processing plants	Achieve, at a minimum, an SO_2 emission reduction efficiency that is determined by the information specified in Tables 1 and 2 of 40 CFR part 60, subpart OOOOa.
Storage Vessels	• Control VOC emissions using vapor recovery or combustion control device to reduce emissions by 95 percent. • Applies to storage vessels with a potential to emit (PTE) equal to or greater than 6 tons per year (tpy) of VOC.

A complete copy of the final rule can be found in the Federal Register (Volume 81, Number 107, p. 35824) at **https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7562.** The codification of the final rule's subpart can be found in the electronic CFR (eCFR): Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015 at **http://www.ecfr.gov/**. The docket for this rule, which includes supporting technical documents as well as public comments, is available on **http://www.regulations.gov/**, docket ID number EPA-HQ-OAR-2010-0505.

1.3 What is the compliance timetable for the rule?

The compliance date for the rule is August 2, 2016 or startup of the affected facility, whichever is later. For well completions (with some exceptions) and pneumatic pumps, the rule provides a phase in period of 180 days to allow time to address the demand for equipment and personnel to meet the standards in the rule. For fugitive emissions monitoring at well sites and compressor stations, the rule provides a phase in period for the conduct of monitoring and repair until June 3, 2017. We have provided a compliance timetable based on the specific requirements for the individual affected facilities in the sections below.

The initial compliance period for the rule begins on August 2, 2016 or upon startup date of an affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text] The initial compliance period may be less than one full year. [§60.5410a introductory text] Annual reports are due 90 days after the end of the initial compliance period and within one year thereafter.

1.4 How do I use this guide?

1.4.1 What does the guide cover?

This guide covers the affected facilities under the subpart OOOOa rule as outlined in **Table 1-1** above. Although the intended audience for this guide are small business entities, the compliance guide is generally applicable to all entities subject to the rule.

1.4.2 Structure and content of the guide

Section 2 of the guide describes what specific entities and affected sources are covered by the rule as outlined in the preamble to final rule.

Sections 3 through 11 address the specific requirements applicable to the affected facilities subject to the rule. Each of those sections includes information such as:

- How to determine the affected facility status of an emission source

- What requirements apply to the affected facility
- When compliance is required
- What testing and monitoring requirements apply
- What notification and reporting requirements apply
- What records must be kept

Section 12 provides an overview of the regulatory entities that implement and enforce the requirements of the rule and covers how to report a violation of the rule.

Section 13 provides additional information that might be helpful in complying with the rule, including:

- Who to contact for further assistance or for questions
- How to find the rulemaking and related documents
- Information about the compliance assurance process (enforcement)
- How to minimize harm and how pollution prevention might affect your operation

In this guide, we provide an overview of the requirements in a more easy-to-understand format based on the type of source. We provide citations to CFR rule sections throughout this guide in order to assist the reader in locating the official rule's wording. For brevity, the nomenclature omits both *40 CFR* and *(2016)* in each citation, as these are common to every citation in this guide. For example, when referring to the official rule section 40 CFR §60.5365a(2016), we simply use §60.5365a. The citations are provided in square brackets following text throughout the guide. For example, the citation would appear as [§60.5365a(f)] after a paragraph of text.

Note a that all references to this "part" refer to 40 CFR part 60 and this "subpart" refer to 40 CFR part 60, subpart OOOOa unless otherwise specified.

For the convenience of the reader, we have provided notation boxes throughout the guide that provide valuable information such as definitions or insights, notes or interpretations. Definitions will be noted in blue shaded boxes, and other comments or information will noted in pink shaded boxes such as those below.

Useful information and commentary is included in pink shaded boxes within the document.

***Definitions** of pertinent terms are included in blue shaded boxes within the text of the section.*

1.4.3 Requirements applicable to all affected facilities

There are several requirements that are common to all affected facilities with respect to submitting annual reports and maintaining records. In addition, there are affected facility specific requirements which are outlined later in this document.

Reporting

- You must submit 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) at **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 (**https://www3.epa.gov/ttn/chief/cedri/**). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. [§60.5420a(b) introduction and (b)(11)]
- The initial annual report is due no later than 90 days after the end of the initial compliance period. As noted above, the initial compliance period ends no later than 1 year after initial startup of your affected facility, or no later August 2, 2017. [§60.5420a(b) introduction]
    - 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. [§60.5420a(b) introduction]
    - Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. [§60.5420a(b) introduction]
    - 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. [§60.5420a(b) introduction]
    - The information specified below should be included in all reports. [§60.5420a(b)(1)
        - the company name,
        - facility site name associated with the affected facility,
        - US Well ID or US Well ID associated with the affected facility, if applicable,
        - address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.
        - an identification of each affected facility being included in the annual report.

- beginning and ending dates of the reporting period.
- a certification by a *certifying official* of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping

- All records required must be maintained either onsite or at the nearest local field office for at least 5 years. [§60.5420a(c) introduction)]
- Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format. [§60.5420a(c) introduction)]

1.4.4 Acronyms and abbreviations

Table 1-2 provides a list of acronyms and abbreviations that are used in this guide along with their explanation.

Table 1-2. Explanation of Acronyms and Abbreviations

Acronym	**Long Name**
API	American Petroleum Institute
bbl	Barrel
BSER	Best Systems of Emission Reduction
CAA	Clean Air Act
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data reporting Interface
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CPMS	Continuous Parameter Monitoring System
eCFR	Electronic Code of Federal Regulations
EPA	Environmental Protection Agency
ft	Feet
GHG	Greenhouse Gas
GOR	Gas to Oil Ratio
H_2S	Hydrogen Sulfide
LDAR	Leak Detection and Repair
LT/D	Long Tons per Day
Mcf	Thousand Cubic Feet
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
OAQPS	Office of Air Quality Planning and Standards

OGI	Optical Gas Imaging
ppm	Parts per Million
psia	Pounds per Square Inch Absolute
PTE	Potential to Emit
REC	Reduced Emissions Completion
SBREFA	Small Business Regulatory Enforcement Fairness Act of 1996
scf	Standard Cubic Feet
scf/day	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
SO_2	Sulfur Dioxide
STBOD	Standard barrels of oil per day
tpy	Tons per Year
VOCs	Volatile Organic Compounds
VRU	Vapor Recovery Unit
XML	Extensible Markup Language
°C	Celsius
°F	Fahrenheit

2.0 What Entities and Affected Facilities are Subject to the Rule?

The entities that could potentially be subject to the rule compose several categories of activity in the oil and natural gas industry. If an entity operates under the Industrial Source Categories outlined below in Table 2-1, those entities could potentially be subject to the rule.

Table 2-1. Industrial Source Categories Affected By Subpart OOOOa

Category	NAICS Code[a]	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.

a. North American Industry Classification System.

As noted in the preamble to the rule, this table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by the rule. This table lists the types of entities that the EPA is now aware could potentially be affected; however, other types of entities not listed in the table could also be regulated.

To understand *who* is subject to the rule's requirements, it is important to understand what types of "affected facilities" are covered by the rule. If an entity owns or operates an affected facility as outlined in the rule, the owner or operator is subject to the rule. An owner or operator may have one or more affected facilities at the same location.

> ***Affected facility*** *means any apparatus to which the standard is applicable. An owner or operator may have one or several affected facilities at the same location.*

Subpart OOOOa applies to owners and operators of affected facilities outlined in **Table 2-2** where construction, modification or reconstruction commenced after September 18, 2015. The definition of modification and reconstruction for an affected facility defaults to the definition provided in the General Provisions of 40 CFR subpart 60, except for where a source-specific definition is included in the rule.

Table 2-2. Types of Affected Facilities Subject to Subpart OOOOa

Guide Section	Affected Facility	Location
3.0	Well Completions (for hydraulically fractured wells)	All*
4.0	Wet seal centrifugal compressors	All (except located at well sites)
5.0	Reciprocating compressors	All (except located at well sites)
6.0	Pneumatic controllers	All*
7.0	Natural gas driven pumps	Located at natural gas processing plants and at well sites
8.0	Storage Vessels	All*
9.0	Collection of fugitive emissions components	Well sites and compressor stations
10.0	Equipment Leaks at natural gas processing plants (except compressors)	All natural gas processing plants
11.0	Sweetening units at natural gas processing plants	All natural gas processing plants

* Some exemptions or emission thresholds apply. See specific guide section for description of affected facility.

3.0 GHG and VOC Standards for Well Affected Facilities

3.1 How do I determine if my well is an affected facility?

The *well* requirements of subpart OOOOa apply to well completion operations at each well affected facility. A single *well* is an affected facility if:

- It conducts a well completion operation after *hydraulically fracturing* of a well that commenced construction after September 18, 2015; or
- It conducts a well completion operation after *hydraulically refracturing* for which refracturing commenced after September 18, 2015. [§60.5365a(a)]

> *The well completion standards in this final rule apply to both natural gas and oil well completions.*

> ***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.*
> ***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.*

> *A well that is refractured, and for which the well completion operation is conducted according to the requirements of §60.5375a(a)(1)-(4), is not an affected facility for purposes of the well completion standards.*

3.2 How do I comply?

The requirements that apply to a *well* affected facility vary depending on the type of the well affected facility.

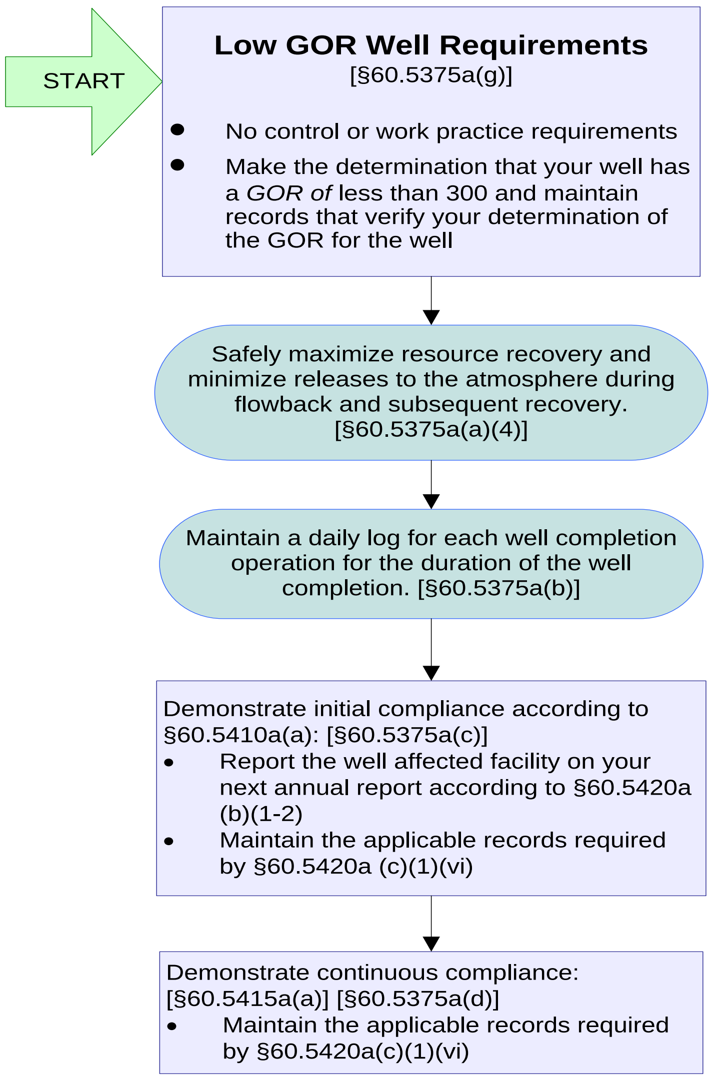
As shown in the figures, there are three types of well affected facility requirement scenarios:

- Low gas to oil ratio (GOR). A low GOR well is a well affected facility with less than 300 scf of gas per stock tank barrel of oil produced. These wells are required to comply with the requirements of §60.5375a(g). See **Figure 3-1** for an overview of the requirements for low GOR wells.
- Low pressure, delineation and wildcat wells. These wells are required to comply with the control requirements of §60.5375a(f)(3)-(4). See **Figure 3-2** for an overview of the

requirements for these wells.

- Non-low pressure, non-delineation and non-wildcat wells. These wells are required to comply with the control requirements of §60.5375a(a)(1)-(4)[2]. See **Figure 3-3** for an overview of the requirements for these wells.

Figure 3-1. Requirements for Low GOR Well Affected Facilities



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[2] The rule provides for a phase in period for the non-low pressure, non-delineation and non-wildcat wells during which these wells comply with the requirements for delineation/wildcat wells. See "When must I comply?" below for further discussion of the initial phase in period.

Figure 3-2. Requirements for Low Pressure, Delineation and Wildcat Well Affected Facilities

START

Low Pressure Well, Delineation Well, and Wildcat Well Requirements [§60.5375a(f)]

- Route all flowback 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.
- Alternatively, you may route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function.
- Any gas present in the flowback before the separator can function is not subject to control requirements. [§60.5375a(f)(3)(ii)]
- You must capture and direct recovered gas from the separator 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. [§60.5375a(f)(3)(ii)]
- Each completion combustion device must be equipped with a reliable continuous pilot flame. [§60.5375a(f)(3)(ii)]

↓

Maintain a daily log for each well completion operation for the duration of the well completion. [§60.5375a(b)]

↓

Demonstrate initial compliance according to §60.5410a(a): [§60.5375a(c)]

- Submit the notification per §60.5420a(a)(2)
- Submit annual report according to §60.5420a(b)(1) and (2)
- Maintain the applicable records required by §60.5420a(c)(1)

↓

Demonstrate continuous compliance: [§60.5415a(a) [§60.5375a(d)]

- Maintain the applicable records required by §60.5420a(c)(1)
- Submit annual report according to §60.5420(b)(1) and (2)

Figure 3-3. Requirements for Non-Low Pressure, Non-Delineation and Non-Wildcat Well Affected Facilities

START

Non-Low pressure, Non-Delineation and Non-Wildcat Well Requirements
[§60.5375a(a)]

- 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. [§60.5375a(a)(1)(i)]
- Any gas present in the initial flowback stage is not subject to control under this section. [§60.5375a(a)(1)(i)]

- During the separation flowback stage, do one of the following unless is it technically infeasible to operate the separator: [§60.5375a(a)(1)(ii)]
  - 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 onsite fuel source, or
    - Use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.
- If, during the separation flowback stage, it becomes technically infeasible for a separator to function, comply with the initial flowback stage requirements. [§60.5375a(a)(1)(ii)]
- If it is technically infeasible to route the recovered gas from the separator flowback stage as required above, 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. Document the reasons for the technical infeasibility determination per §60.5420a(c)(1)(iii)(A) [§60.5375a(a)(3)].

Safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery. [§60.5375a(a)(4)]

Maintain a daily log for each well completion operation for the duration of the well completion. [§60.5375a(b)]

No direct venting of gas is allowed during the separation flowback stage unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways.

- Have a separator onsite during the entire flowback period. [§60.5375a(a)(1)(iii)].
- You do not have to have a separator onsite during flowback if your well is not hydraulically fractured or refractured with liquids, or the well does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site. [§60.5375a(a)(1)(iii)(A)]
- If subsequently the conditions at the well allow for liquid collection, then immediately stop the well completion operation, install a separator, and restart the well completion operation and comply with the liquids and gas recovery requirements for the separation flowback stage. [§60.5375a(a)(1)(iii)(B)]
- Completion combustion devices used to control emissions must be equipped with a reliable continuous pilot flame. [§60.5375a(a)(3)].

Routing of the flowback to a separator is required as soon as a separator is able to function (i.e., the operator must route the flowback to a separator unless it is technically infeasible for a separator to function). Any gas in the flowback prior to the point at which a separator begins functioning is not subject to control.

See definitions below

Demonstrate initial compliance according to §60.5410a(a): [§60.5375a(c)]
- Submit the notification per §60.5420a(a)(2)
- Submit annual report according to §60.5420a(b)(1) and (2)
- Maintain the applicable records required by §60.5420a(c)(1)

Demonstrate continuous compliance: [§60.5415a(a) [§60.5375a(d)]
- Maintain the applicable records required by §60.5420a(c)(1)
- Submit annual report according to to §60.5420(b)(1) and (2)

Completion combustion device *means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.*
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.*
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.*
Flow line *means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.*
Initial flowback stage *means the period during a well completion operation that begins at the onset of flowback and ends at the separation flowback stage.*
Intermediate hydrocarbon liquid *means any naturally occurring, unrefined petroleum liquid.*
Liquid collection system *means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.*
Recovered liquids *means any crude oil, condensate or produced water recovered through the separation process during flowback.*
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.*
Recovered gas *means gas recovered through the separation process during flowback.*
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.*
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.*

3.3 When must I comply?

The compliance schedule is the same for all three types of well affected facilities. **Figure 3-4** provides an overview of the compliance schedule for well completion operations.

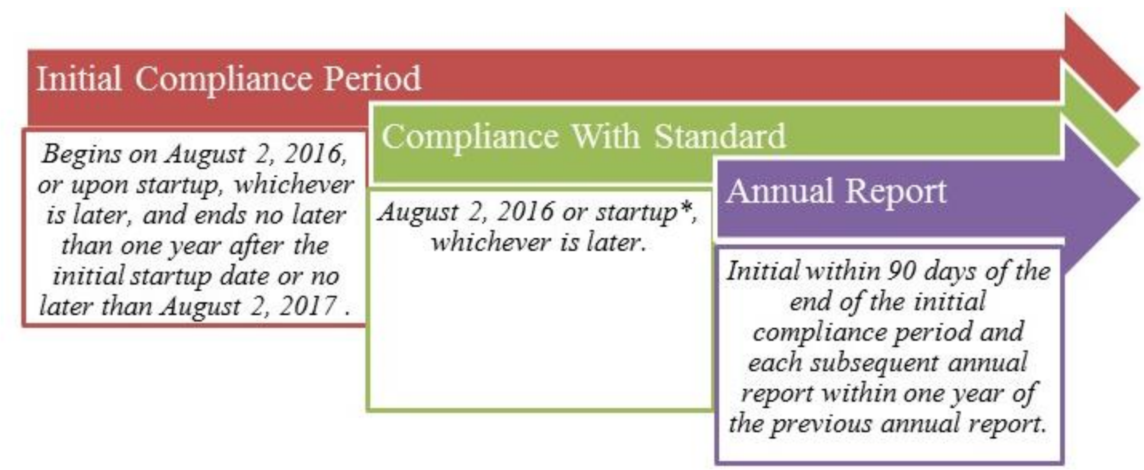
The initial compliance period begins on August 2, 2016 or upon startup of flowback, whichever is later, and ends no later than one year after the initial startup date or no later than August 2, 2017.

For well affected facilities subject to the non-low pressure, non-delineation, and non-wildcat well affected facility requirements, the rule provides an initial phase in period for complying with the requirements in §60.5375a(a)(1) through(4). Due to the potential for near term unavailability of REC equipment, the rule provides that until November 30, 2016 these wells must comply with the requirements for delineation and wildcat wells.

However, this phased in compliance period does not apply to well affected facilities already subject to requirements under subpart OOOO, which due to refracturing, could also be subject to subpart OOOOa. Therefore, if your well affected facility commenced refracturing after September 18, 2015 but prior to November 30, 2016, and the well was previously an affected facility subject to subpart OOOO requirements, the owner operator must be in compliance with the requirements in §60.5375a(a)(1) through(4) upon startup of flowback.

> *Note: The phase in period only applies to non-low pressure, non-delineation and non-wildcat wells. The requirements for all other well affected facilities are the same during and after the phase in period.*

Figure 3-4. Compliance Schedule for Well Completion Operations



*With the exception of the initial phase in period that applies to non-low pressure, non-delineation and non-wildcat wells. See discussion of phase in period above.

3.4 What, when and to whom must I report?

You are required to submit a notification as required in §60.5420a(a)(2) for all wells except low GOR well affected facilities.

In addition to the information outlined in section 1.4.3 above, you must include the information outlined in §60.5420a(b)(2) of the rule in your annual report for your well affected facility.

A well completion following hydraulic fracturing or refracturing is reported once only in the first annual report following the completion event. Subsequent completions of the same well following refracturing are reported in the annual report which covers the time period in which the well completion operation occurred.

3.5 What records must I keep?

You must maintain the records for each well completion operation. Specifically, you must maintain the records outlined in §60.5420a(c)(1), as applicable.

4.0 GHG and VOC Standards for Centrifugal Compressor Affected Facilities

4.1 How do I determine if my centrifugal compressor is an affected facility?

If you own or operate a centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals, constructed, modified or reconstructed after September 18, 2015, your centrifugal compressor is an affected facility.

The rule does not establish requirements for centrifugal compressors located at well sites.

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.*

Dry seal centrifugal compressors are not affected facilities.

If your centrifugal compressor is located at a well site, or an adjacent well site and services more than one well site, it is not considered an affected facility. [§60.5365a(b)]

4.2 How do I comply?

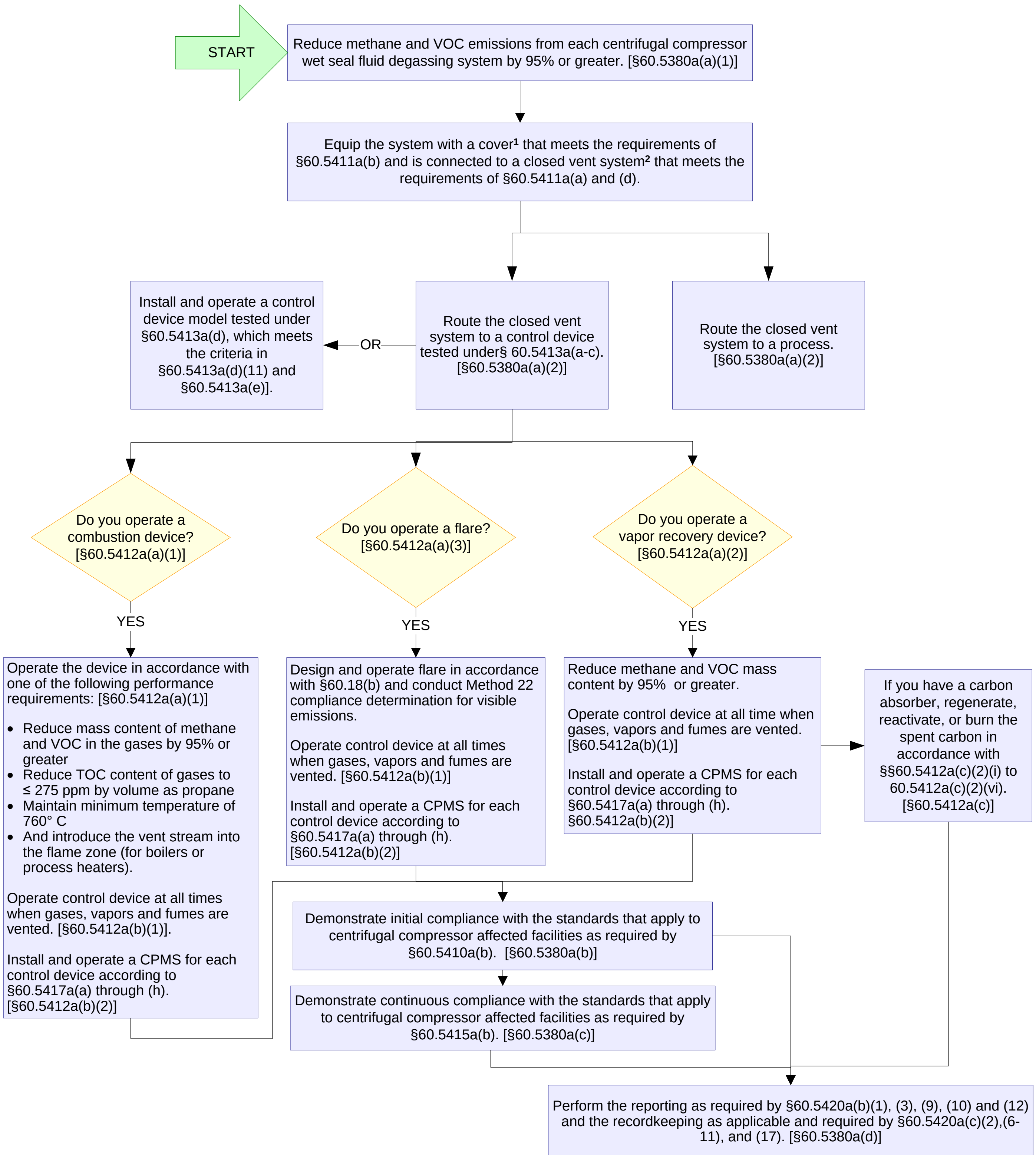
To meet the standard for centrifugal compressors you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. [§60.5380a(a)(1)]

An operator may use a cover and closed vent system to route emissions to a control device or to a process. The rule includes requirements for cover, closed vent systems and control devices that must be met to demonstrate the 95 percent emission reduction requirement. The rule does not have requirements for the process to which you may route the compressor emissions, however, the same closed vent system and cover requirements apply to this control scenario. All of these requirements include reporting and recordkeeping provisions.

For covers and closed vent systems, you must meet specific requirements related to design and installation of the covers and closed vent systems, initial and ongoing inspections, repair, and recordkeeping. For control devices, the rule provides requirements for design and installation of the control devices, initial performance testing, installation and operation of a continuous parameter monitoring system (CPMS), periodic performance testing and reporting and recordkeeping.

Figure 4-1 provides an overview of the requirements for your centrifugal compressor affected facility.

Figure 4-1. Subpart OOOOa Requirements for Centrifugal Compressor Affected Facilities



Footnotes:

1 §60.5411a(b) cover requirements:

- Form a continuous barrier over entire surface area of the liquid.
- Secure each cover opening in a closed, sealed position, except when adding or removing material; conducting inspections, sampling, repairs or maintenance; or venting to a closed vent system.

2 §60.5411a(a) closed vent system requirements:

- Route all gases, vapors, and fume to a control device or to a process that meets the conditions specified in §60.5412a(a) through (c).
- Design and operate with no detectable emissions per §60.5416a(b).
- Meet the bypass requirements of §60.5411a(a)(3).

4.3 When must I comply?

With the exception of performance testing for your control device (see below), you must comply with all requirements for your centrifugal compressor by August 2, 2016, or upon startup, whichever is later.

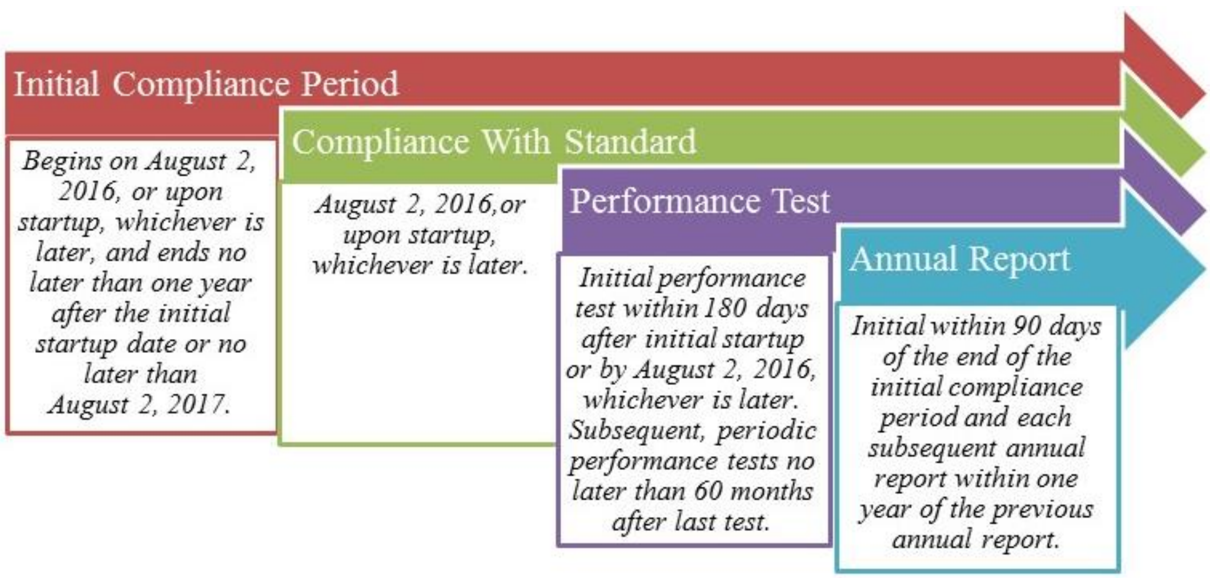
You must conduct an initial performance test for your control device as required in §60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later. [§60.5413a(b)(5)(i)]

You must also conduct a periodic performance test no later than 60 months after the initial performance test and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test. [§60.5413a(b)(5)(ii)]

You must submit your first annual report within 90 days after the end of the initial compliance period. The initial compliance period begins on August 2, 2016, or upon startup date of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text]

Figure 4-2 provides an overview of the compliance schedule for your centrifugal compressor.

Figure 4-2. Compliance Schedule for Centrifugal Compressors



4.4 What testing or monitoring is required?

If you use covers and closed vent systems to capture and route emissions to a control device or to a process you are required to do an initial assessment of the systems to ensure they demonstrate no detectable emissions and, on an ongoing basis, you must inspect them annually according to inspection criteria and methods outlined in the rule.

If you use a control device to reduce emissions, you must conduct an initial performance testing on the control device within 180 days after initial startup or by August 2, 2016, whichever is later. On an ongoing basis, you must retest the control device at least every 60 months after the initial performance test.[3]

You must demonstrate the performance of the control device on a continuing basis by setting limits on monitored parameters during the initial performance test. To demonstrate the performance level of the control device, you must develop a site specific monitoring plan and monitor your control device using a CPMS. You must calculate the daily average of the monitored parameter and compare it to the limit determined during the performance test[4]. You must keep records of the data from the CPMS and any repairs or deviations as required in the rule.

If you use a combustion control device, you must also maintain a continuous pilot flame at all times of operation and conduct monthly visible emissions tests. You must conduct the visible emissions test for 15 minutes using EPA Method 22. Devices must be operated with no visible emissions, except for periods not to exceed 1 minute during any 15-minute period.[§60.5415a(b)(2)].

4.5 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 above, you must include the information outlined in §60.5420a(b)(3) of the rule in your annual report for your centrifugal compressor affected facility.

4.6 What records must I keep?

You must maintain the records for each of your centrifugal compressors, and for any cover, closed vent system, control device or CPMS used to comply with the emission reduction requirements. Specifically, you must maintain the records outlined in §60.5420a(c)(2), (6), (7), (8), (9), (10), (11), and (17), as applicable, for each centrifugal compressor, cover, closed vent system or control device.

[3] There are exceptions to this requirement. Condensers and carbon adsorbers may use a design analysis instead of conducting a performance test. [§60.5413a] Manufacturer tested enclosed combustion devices that are listed on the EPA website at **www.epa.gov/airquality/oilandgas** are tested before they are installed on a site. Additionally, you do not have to perform periodic testing for these devices if you choose to continuously monitor gas flow rate. Likewise, if your combustion device meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) and you establish a correlation between firebox or combustion chamber temperature and the TOC performance level, periodic testing is not required. [§60.5413a(b)(5)(ii)(A) and (B)]

[4] If you use a condenser, the condenser efficiency is determined on a daily basis, and then averaged over 365 days. [§60.5415a(b)(2)(viii)]

5.0 GHG and VOC Standards for Reciprocating Compressor Affected Facilities

5.1 How do I determine if my reciprocating compressor is an affected facility?

The rule does not establish requirements for reciprocating compressors located at well sites.

A reciprocating compressor affected facility is each single reciprocating compressor for which construction, modification or reconstruction commenced after September 18, 2015.

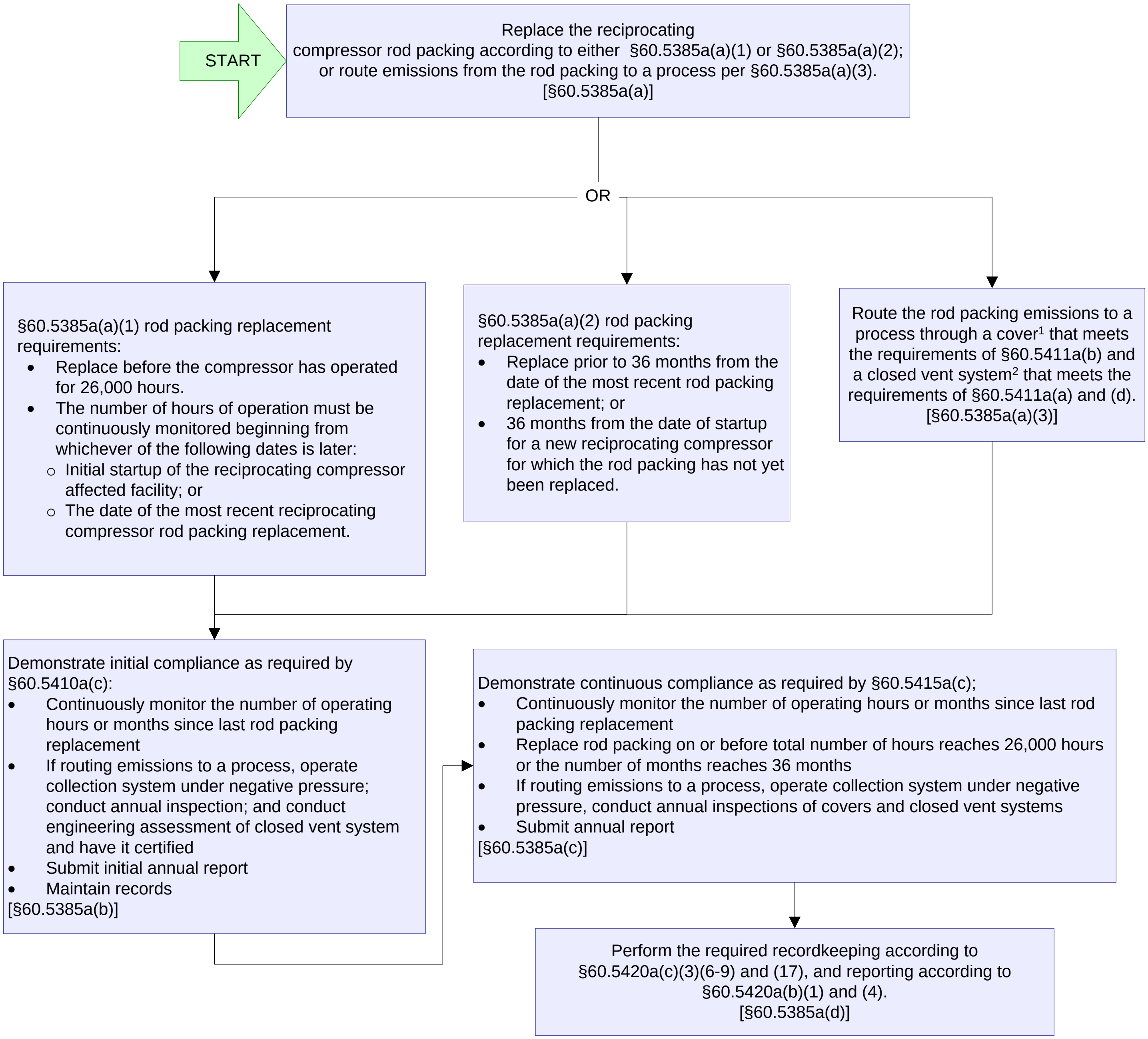
A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility. [§60.5365a(c)]

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, or other mechanism that provides the same function.*

5.2 How do I comply?

To comply with the standard for reciprocating compressor affected facilities, you must either replace the reciprocating compressor rod packing at the intervals defined in the rule or capture the emissions to a process using a rod packing emissions collection system and a closed vent systems that meet the requirements outlined in the rule. **Figure 5-1** provides an overview of the requirements for your reciprocating compressor affected facility.

Figure 5-1. Subpart OOOOa Requirements for Reciprocating Compressor Affected Facilities



Footnotes:

1. §60.5411a(b) cover requirements:
   - Form a continuous barrier over entire surface area of the liquid.
   - Secure each cover opening in a closed, sealed position, except when adding or removing material; conducting inspections, sampling, repairs or maintenance; or venting to a closed vent system.

2. §60.5411a(a) closed vent system requirements:
   - Route all gases, vapors, and fume to a control device or to a process that meets the conditions specified in §60.5412a(a) through (c).
   - Design and operate with no detectable emissions per §60.5416a(b).
   - Meet the bypass requirements of §60.5411a(a)(3)

5.3 When must I comply?

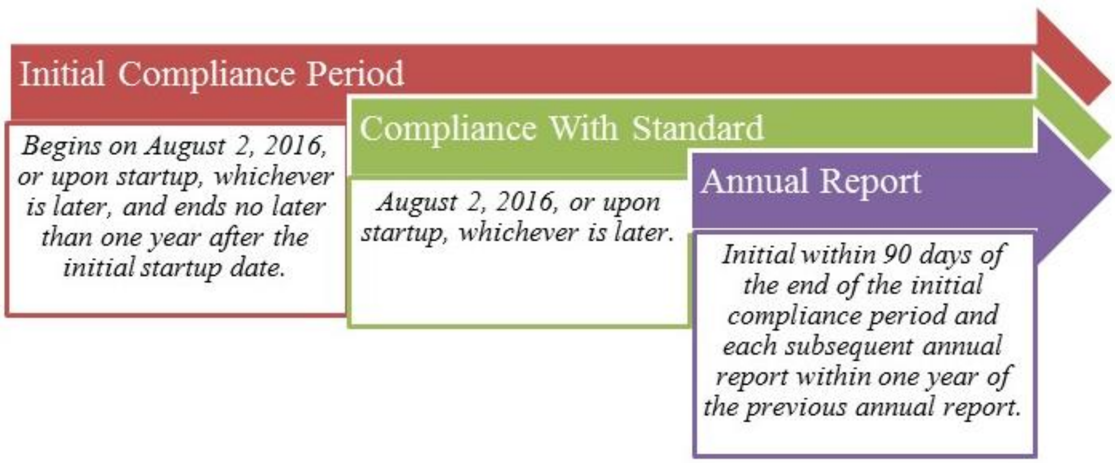
The initial compliance period begins on August 2, 2016, or upon startup date of an affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text]

You must be in compliance with the standards by August 2, 2016 or upon startup of your reciprocating compressor, or whichever is later.

You must submit your initial annual report within 90 days of the end of the initial compliance period, as described above and submit each subsequent annual report within one year of the previous annual report.

Figure 5-2 provides an overview of the compliance schedule for your reciprocating compressor.

Figure 5-2. Compliance Schedule for Reciprocating Compressors



5.4 What testing or monitoring is required?

If you use a rod packing emissions collection system and a closed vent system to capture and route emissions to a process you are required to do an initial assessment of the systems to ensure they demonstrate no detectable emissions and, on an ongoing basis, you must inspect them annually according to inspection criteria and methods outlined in the rule.

5.5 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 above, you must include the information outlined in §60.5420a(b)(4) of the rule in your annual report for your reciprocating compressor affected facility.

5.6 What records must I keep?

You must maintain the records for each of your reciprocating compressors, and for any cover or closed vent system used to comply with the emission reduction requirements. Specifically, you must maintain the records outlined in §60.5420a(c)(3), (6) through (9), and (17), as applicable, for each reciprocating compressor, cover, or closed vent system.

6.0 GHG and VOC Standards for Pneumatic Controller Affected Facilities

6.1 How do I determine if my pneumatic controller is an affected facility?

The rule applies to each, continuous bleed, natural gas-driven pneumatic controllers constructed, modified or reconstructed after September 18, 2015 as follows: [§60.5365a(d)]

- Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.
- Each pneumatic controller affected facility located at other than 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.

Intermittent or snap-action pneumatic controllers and non-natural gas-driven pneumatic controllers are not affected facilities under the rule.

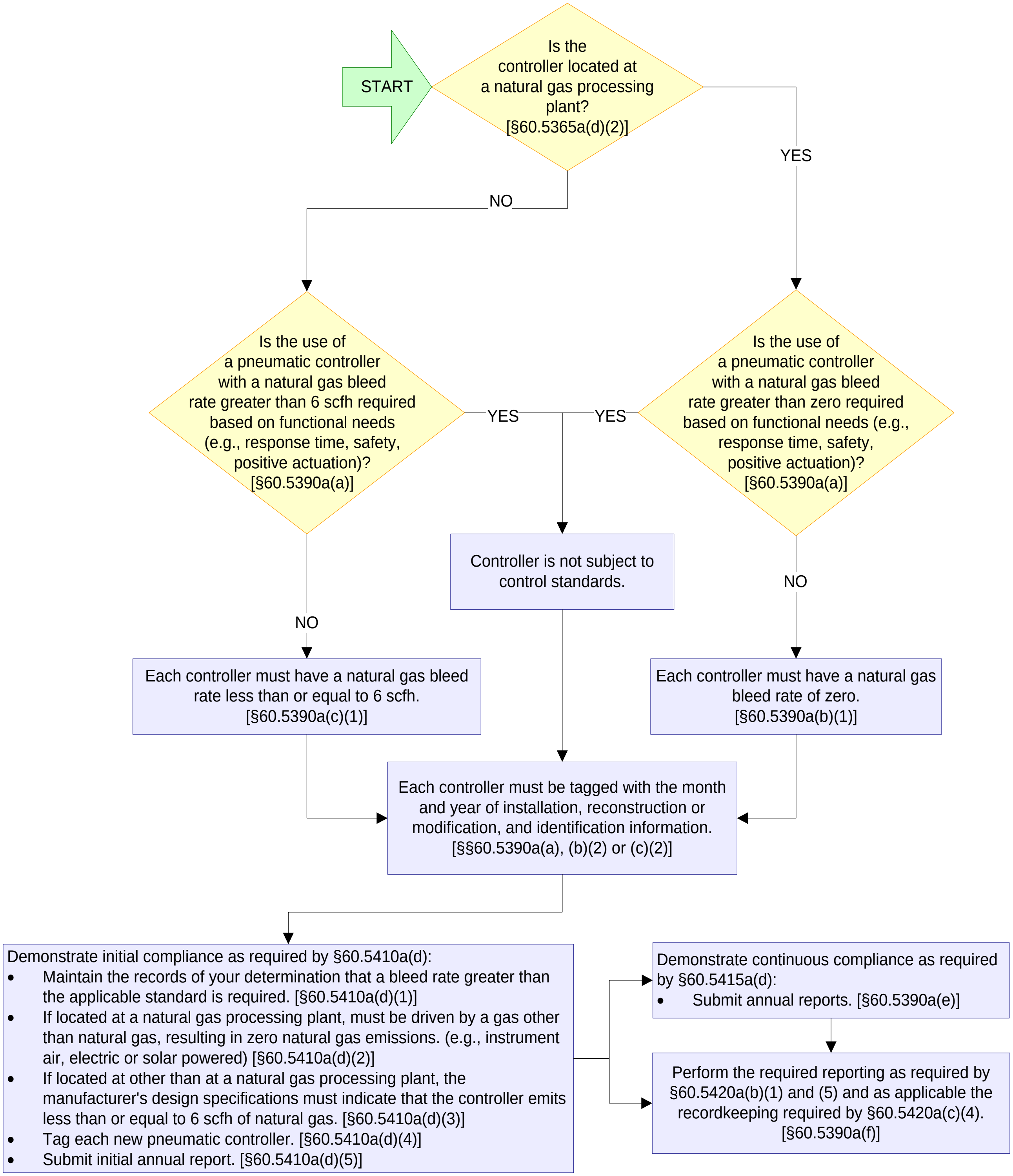
> ***Bleed rate*** *means the rate in scfh at which natural gas is continuously vented (bleeds) from a pneumatic controller.*
> ***Continuous bleed*** *means a continuous flow of pneumatic supply natural gas to a pneumatic controller.*
> ***Intermittent/snap-action pneumatic controller*** *means a pneumatic controller that is designed to vent non-continuously.*
> ***Natural gas-driven pneumatic controller*** *means a pneumatic controller powered by pressurized natural gas.*
> ***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.*
> ***Pneumatic controller*** *means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.*

6.2 How do I comply?

> *The rule provides an exemption for pneumatic controllers for which compliance would pose a functional limitation due to their actuation response time or other operating characteristics.*

For each pneumatic controller affected facility you must reduce GHG and VOC, based on natural gas as a surrogate for GHG and VOC. The control requirements depend on whether the pneumatic controller is located at a natural gas processing plant or located at other than a natural gas processing plant. **Figure 6-1** provides an overview of the applicability and requirements applicable to your pneumatic controller affected facility.

Figure 6-1. Subpart OOOOa Requirements for Pneumatic Controller Affected Facilities



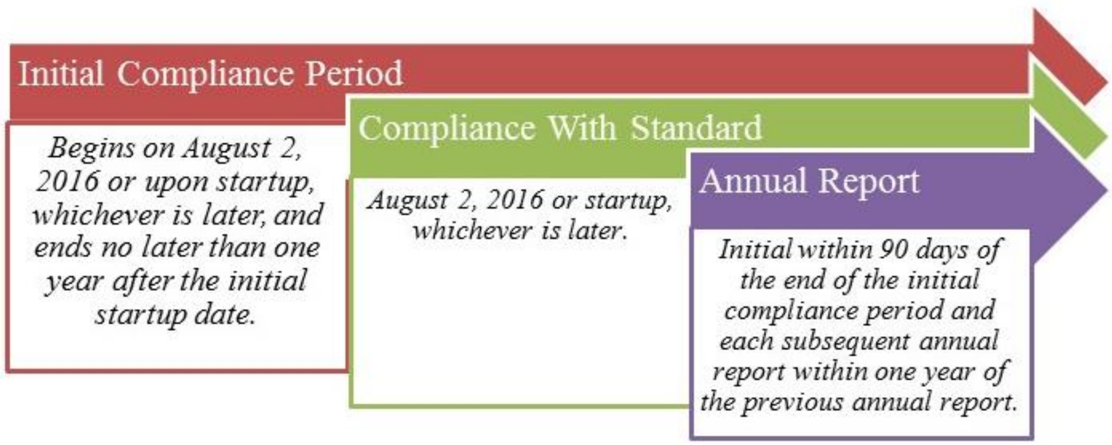
6.3 When must I comply?

You must be in compliance with the initial requirements for pneumatic controller affected facilities by August 2, 2016 or upon startup of the affected facility, whichever is later.

You must submit your first annual report within 90 days of the end of the initial compliance period, which begins on August 2, 2016 and ends no later than August 2, 2017. For a facility with startup after August 2, 2016, the first annual report is due within 90 days of the end the initial compliance period which begins upon startup date of the affected facility, and ends no later than one year after the initial startup date. [§60.5410a introductory text]

Figure 6-2 provides an overview of the compliance schedule for your pneumatic controller.

Figure 6-2. Compliance Schedule for Pneumatic Controllers



6.4 What testing or monitoring is required?

There are no testing or monitoring requirements applicable to pneumatic controller affected facilities.

6.5 What, when and to whom must I report?

In addition to the information outlined in 1.4.3 above, you must include the information outlined in §60.5420a(b)(5) of the rule in your annual report for your pneumatic controller affected facility.

6.6 What records must I keep?

You must maintain the records for each of your pneumatic controller affected facilities. Specifically, you must maintain the records outlined in §60.5420a(c)(4) for each pneumatic controller affected facility.

7.0 GHG and VOC Standards for Pneumatic Pump Affected Facilities

7.1 How do I determine if my pneumatic pump is an affected facility?

Each natural gas-driven diaphragm pump constructed, modified or reconstructed after September 18, 2015 and located at a natural gas processing plant or at a well site is an affected facility.

Natural gas-driven diaphragm pump *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart.*

There are no requirements under the rule for pumps located in the gathering and boosting or transmission and storage segments.

These requirement do not apply to piston pumps or pumps that are driven by means other than natural gas.

A pump located at a well site that operates for any period of time each day for less than a total of 90 days per year, is a limited-use pneumatic pump and is not an affected facility.
Lean glycol circulation pumps are not affected facilities.

7.2 How do I comply?

You must reduce GHG and VOC emissions, based on natural gas as a surrogate for GHG and VOC.

Each pneumatic pump affected facility located at a natural gas processing plant must have a natural gas emission rate of zero (e.g., powered by instrument air, electric, or solar power). Pneumatic pumps at natural gas processing plants that have a natural gas emission rate of zero are not affected facilities; therefore, they have no requirements under the rule. [§60.5393a(a)].

Greenfield site *means a site, other than a natural gas processing plant, which is entirely new construction. For the purposes of the pneumatic pump standards, natural gas processing plants are not considered to be greenfield sites, even if they are entirely new construction.*

For each pneumatic pump affected facility located at a well site that is a greenfield site, you must reduce emissions by 95 percent unless there is not a control device or process available onsite. If there is a control device available, but it is not capable of achieving 95 percent reduction you must still route the emissions to the control device. For each pneumatic pump affected facility located at a well site that is not a greenfield site you must meet the same requirements as above; however, if it is

You are not required to install a new control device on site that is capable of meeting a 95 percent reduction nor are you required to retrofit the existing control device to enable it to meet the 95 percent reduction requirement.

For pumps located at well sites, if a control device or ability to route to a process is not available onsite, the pneumatic pump affected facility is not subject to the emission reduction provisions.

technically infeasible to capture and route the emissions to an existing control device or process you are not required to meet the control standard. [§60.5393a(b)]

You may not claim the technical infeasibility exemption for a pneumatic pump affected facility located at a greenfield site because the circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location, can be addressed in the greenfield site's design and construction.

You must comply with the cover and closed vent system requirements to ensure no detectable emissions as outlined in the rule. [§60.5393a(c)]

There are no compliance requirements for the control devices for pneumatic pump affected facilities.

If you subsequently install a control device or have the ability to route to a process, you are required to reduce emissions by 95 percent (i.e., you must route emissions to the control device or process), unless you meet one of the same conditions as above for a non-greenfield well site. In this case, you must be in compliance within 30 days of startup of the control device or within 30 days of the ability to route to a process. [§60.5393a(b)(3)(ii)]

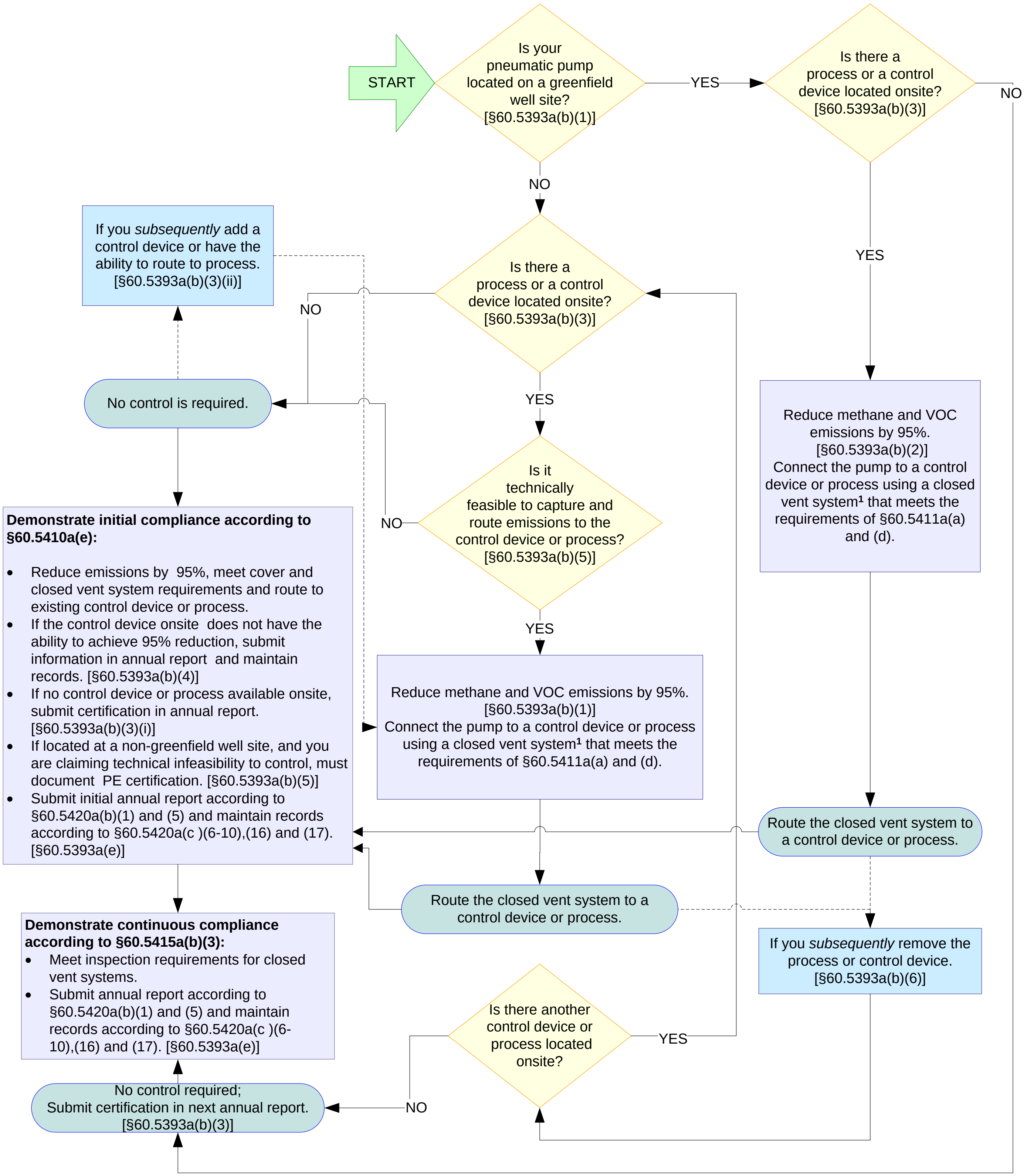
If subsequent to the removal of a control device, you do not have ability to route to a process, then the pneumatic pump affected facility is no longer required to comply with the control requirement.

If a control device is subsequently added to the site, the compliance date for pneumatic pump affected facilities to be routed to the control device is 30 days after startup of the control device.

Figure 7-1 provides an overview of the requirements applicable to pneumatic pump affected facilities located at well sites.

Using an existing control device that is not already subject to subpart OOOO or OOOOa or other compliance requirements (i.e., a control device that is subject to other federal or state compliance requirements) to control pneumatic pump emissions does not make the control device subject to the performance specifications, performance testing, and monitoring requirements of subpart OOOOa.

Figure 7-1. Subpart OOOOa Requirements for Pneumatic Pumps Located at Well Sites



Footnotes:

1. §60.5411a(a) closed vent system requirements:
- Route all gases, vapors, and fume to a control device or to a process that meets the conditions specified in §60.5412a(a) through (c).
- Design and operate with no detectable emissions per §60.5416a(b).
- Meet the bypass requirements of §60.5411a(a)(3).

7.3 When must I comply?

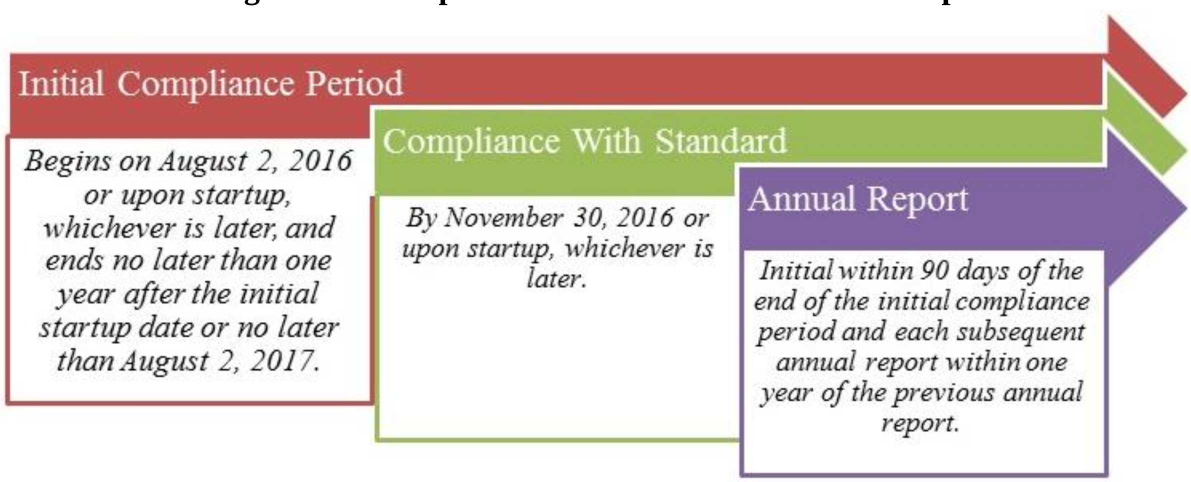
For each pneumatic pump affected facility you must comply with the GHG and VOC emission reduction standards, as applicable, on November 30, 2016, or upon startup, whichever is later. [§60.5393a introductory text]

You must submit your first annual report within 90 days after the end of the initial compliance period, which begins on August 2, 2016 or upon startup of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text]

You must be in compliance with the requirements related to subsequent installation of a control device at a non-greenfield site within 30 days of startup of the control device or within 30 days of the ability to route to a process. [§60.5393a(b)(3)(ii)]

Figure 7-2 provides an overview of the compliance schedule for your pneumatic pump.

Figure 7-2. Compliance Schedule for Pneumatic Pumps



7.4 What testing or monitoring is required?

There are no testing or monitoring requirements under NSPS OOOOa for control devices or processes used to control emissions from your pneumatic pump affected facilities. If the control device is used to control emissions from other affected facilities at your site, refer to those sections for testing and monitoring requirements.

If you are complying with the standard by collecting emissions and routing the emissions to a control device or process through a closed vent system, you must meet specific requirements for the closed vent system. [§60.5393a(c)]

7.5 What, when and to whom must I report?

In addition to the information outlined in 1.4.3 above, you must include the information outlined in §60.5420a(b)(8) of the rule in your annual report for your pneumatic pump affected facility.

7.6 What records must I keep?

You must maintain records for each of your pneumatic pump affected facilities. Specifically, you must maintain the records outlined in §60.5420a(c)(6), (8) through (10), (16) and (17), as applicable, for each pneumatic pump affected facility.

8.0 VOC Standards for Storage Vessel Affected Facilities

8.1 How do I determine if my storage vessel is an affected facility?

40 CFR part 60 subpart OOOOa storage vessel requirements apply to a single *storage vessel* with a PTE greater than or equal to 6 tpy of VOC emissions. [§60.5365a introductory text] that commenced construction, modification, or reconstruction after September 18, 2015. [§60.5365a(e)]

> ***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)(1) 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.*

Exemptions:

- A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility. [§60.5365a(e)(5)]
- 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. [§60.5395a(e)]

A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy remains an affected facility.

A storage vessel that is removed from service and subsequently reconnected to the original source of liquids is subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace a storage vessel affected facility is subject to the same requirements that apply to the storage vessel being replaced.

You must determine PTE within 30 days of liquids first entering the storage vessel. [60.5365a(e)(1)] When determining PTE:

- Do not include vapor that is recovered and vented to a process through a vapor recovery unit (VRU) in your VOC PTE calculations, provided that you comply with §60.5365a(e)(3).
- For storage vessels receiving liquids from well affected facilities subject to §60.5375a (well completions), determine the PTE for VOC emissions within 30 days after the startup of production of the well. [§60.5365a(e)(1)]

You determine the PTE for your single storage vessel using:

- A generally accepted model or calculation methodology, and
- The *maximum average daily throughput* for a 30-day period of production.

> ***Maximum average daily throughput*** *means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.*

The period of production used for the throughput calculation must be the 30-day period prior to the applicable emission determination deadline. [§60.5365a(e) introductory text]

- You may consider in the determination any legally and practically enforceable emission limit in an operating permit or other requirement established under a federal, state, local or tribal authority. [§60.5365a(e) introductory text]

> *By considering, it means that the emissions that are controlled due to a legally and practically enforceable emission limit are not counted for the purposes of the determining the storage vessel's PTE VOCs.*

A storage vessel that is removed from service is no longer an affected facility during the period of removal provided you meet the requirements of §60.5395a(c).

A storage vessel affected facility that is returned to service and is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced. The control requirements apply immediately upon startup, startup of production or return to service. [§60.5365a(e)(4)].

> ***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 (and you meet the requirements listed above).*
> ***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.*

The emission determination deadline is dependent on the type of storage vessel as outlined in **Table 8-1** below:

Table 8-1. Emission Determination Deadline

Type of storage vessel	Emission determination deadline
New, modified, or reconstructed storage vessel other than well completion liquids storage vessels.	Within 30 after the first liquids have entered the storage vessel. [60.5365a(e)(1)]
A storage vessel receiving well completion liquids for well affected facilities subject to §60.5375a, including wells subject to §60.5375a(f).	Within 30 days after *startup of production* of the well. [60.5365a(e)(1)]

8.2 How do I comply?

8.2.1 Control requirements [§60.5395a(a)]

If the PTE for your storage vessel affected facility is determined to be equal to or greater than 6 tpy of VOC, then you have to reduce your emissions by 95 percent. You have to capture your emissions and either reduce emissions using a control device or route the emissions to a process.

If your storage vessel is used for completion liquids under the well completion operations requirements (§60.5375a(a)(1)(i) or (ii)), you must reduce your emissions by 95 percent within 60 days of *startup of production* of the well.

> ***Startup of production*** *means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.*

After compliance with the 95 percent reduction of emissions for at least 12 consecutive months, you may continue to comply with the 95 percent reduction or can change your method of compliance to an uncontrolled actual VOC emissions rate of 4 tpy. To make this change, you must 1) comply with the 95 percent reduction of emissions for at least 12 months; 2) demonstrate that uncontrolled VOC emissions have remained less than 4 tpy (as determined monthly for 12 consecutive months); 3) determine the uncontrolled actual VOC emissions each month; and 4) maintain your uncontrolled actual VOC emissions at less than 4 tpy. The uncontrolled actual VOC emissions calculation determination each month is done using a generally accepted model or calculation methodology and based on the average throughput for each month. If at any time the uncontrolled actual emissions rate increases to 4 tpy or greater, you must again comply with the 95 percent reduction, and within 30 days of the determination of the emissions increase. You must also cease compliance with the 4 tpy uncontrolled actual VOC emissions rate if the well feeding the storage vessel affected facility undergoes fracturing or refracturing (regardless of the emissions rate). Under this scenario, you must comply with the 95 percent reduction standard as soon as liquids from the well are routed to the storage vessel.

Figures 8-1 and 8-2 provide an overview of the requirements for your storage vessel affected facility.

8.3 When must I comply?

Initial compliance includes that you determine the PTE, reduce emissions by 95 percent, use a control device that meets all requirements, and submit your initial annual report and maintain applicable records. You must demonstrate initial compliance by: [§60.5410a(h)]

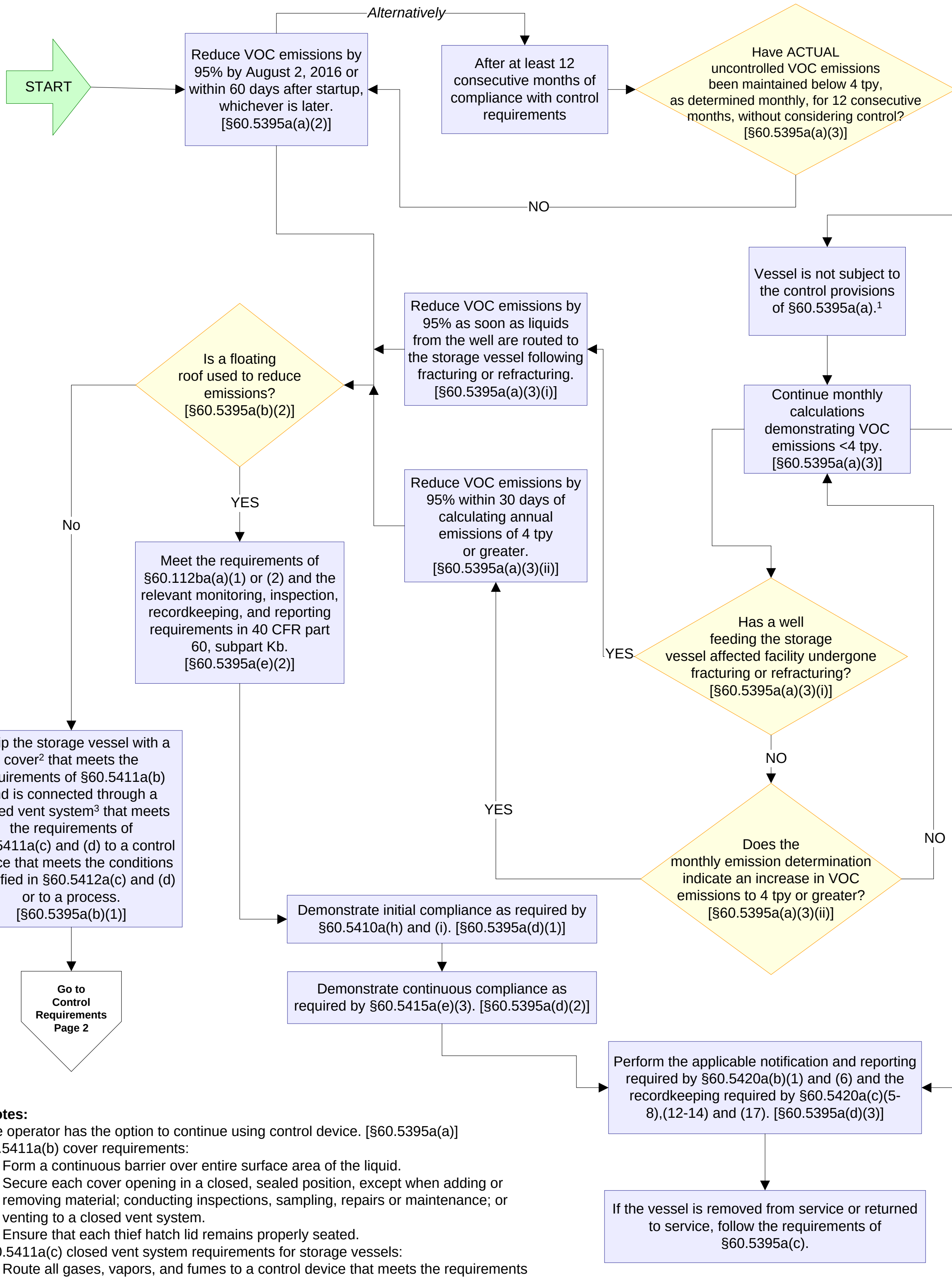
- For storage vessels not located at well sites, August 2, 2016 or within 60 days after startup, whichever is later.
- For storage vessels located at well sites:
  - August 2, 2016 or within 60 days after startup, whichever is later, if there are no other wells present at the wellsite, or
  - August 2, 2016 or immediately upon startup, whichever is later, if there are other wells present at the wellsite.

If you are using a control device, you must conduct initial performance testing of the control device within 180 days of August 2, 2016, or within 180 days of initial startup, whichever is later.

You must submit your first annual report within 90 days after the end of the initial compliance period, which begins on August 2, 2016 or upon startup date of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text]

Figure 8-3 and **Figure 8-4** provide an overview of the compliance schedule for your storage vessel located at other than a well site and located at a well site where no other existing storage vessels are located, respectively.

Figure 8-1. Subpart OOOOa Requirements for Storage Vessel Affected Facilities



Footnotes:

1. The operator has the option to continue using control device. [§60.5395a(a)]
2. §60.5411a(b) cover requirements:
   - Form a continuous barrier over entire surface area of the liquid.
   - Secure each cover opening in a closed, sealed position, except when adding or removing material; conducting inspections, sampling, repairs or maintenance; or venting to a closed vent system.
   - Ensure that each thief hatch lid remains properly seated.
3. §60.5411a(c) closed vent system requirements for storage vessels:
   - Route all gases, vapors, and fumes to a control device that meets the requirements of §60.5412a(c) and (d) or to a process.
   - Design and operate with no detectable emissions. Must be operational 95% of the year or more.
   - Meet the bypass requirements of §60.5411a(c)(3).

Figure 8-2. Subpart OOOOa Requirements for Storage Vessel Affected Facilities (continued)

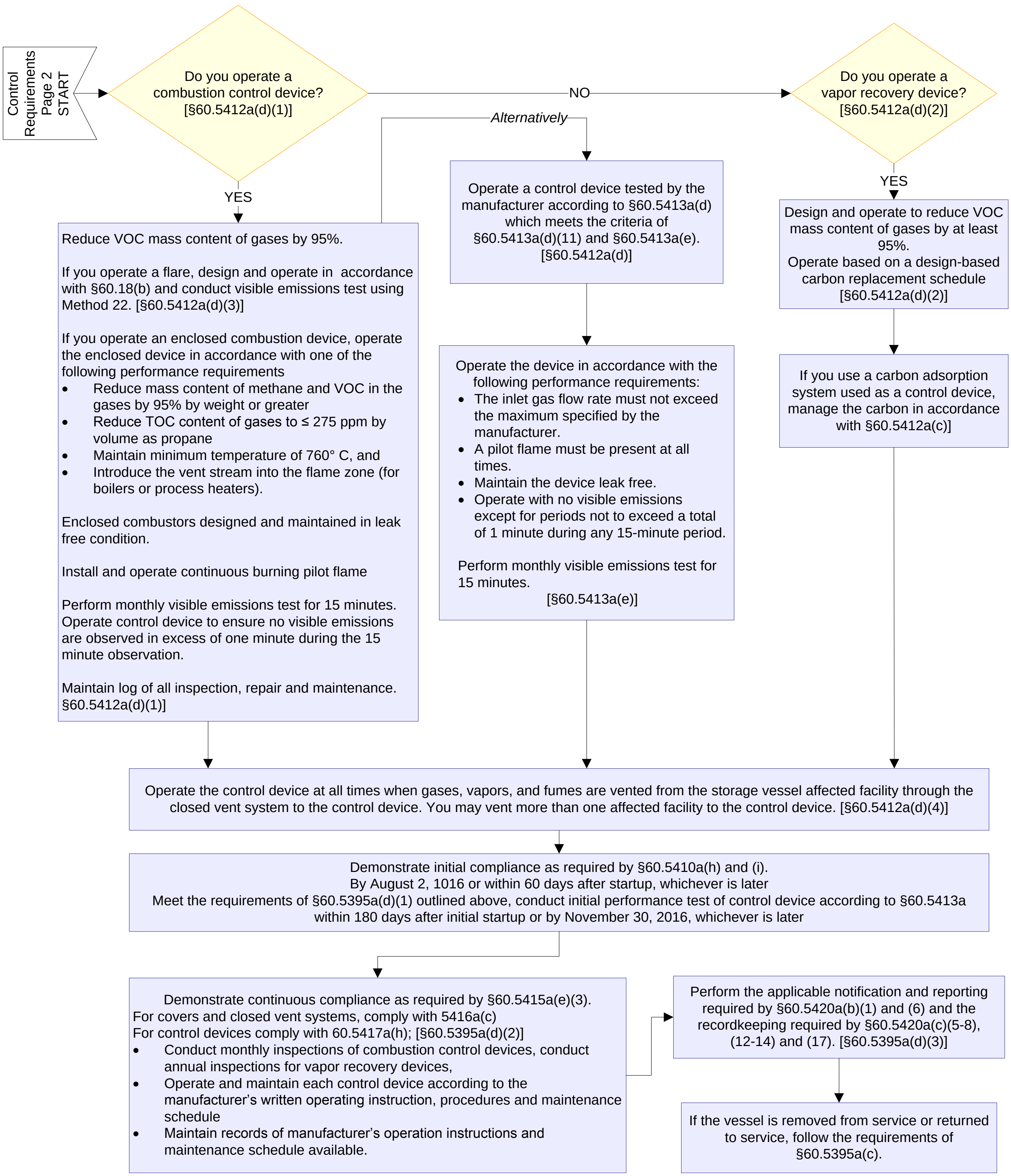


Figure 8-3. Compliance Schedule for Storage Vessels Located at a Well Site Where No Other Existing Storage Vessels are Located

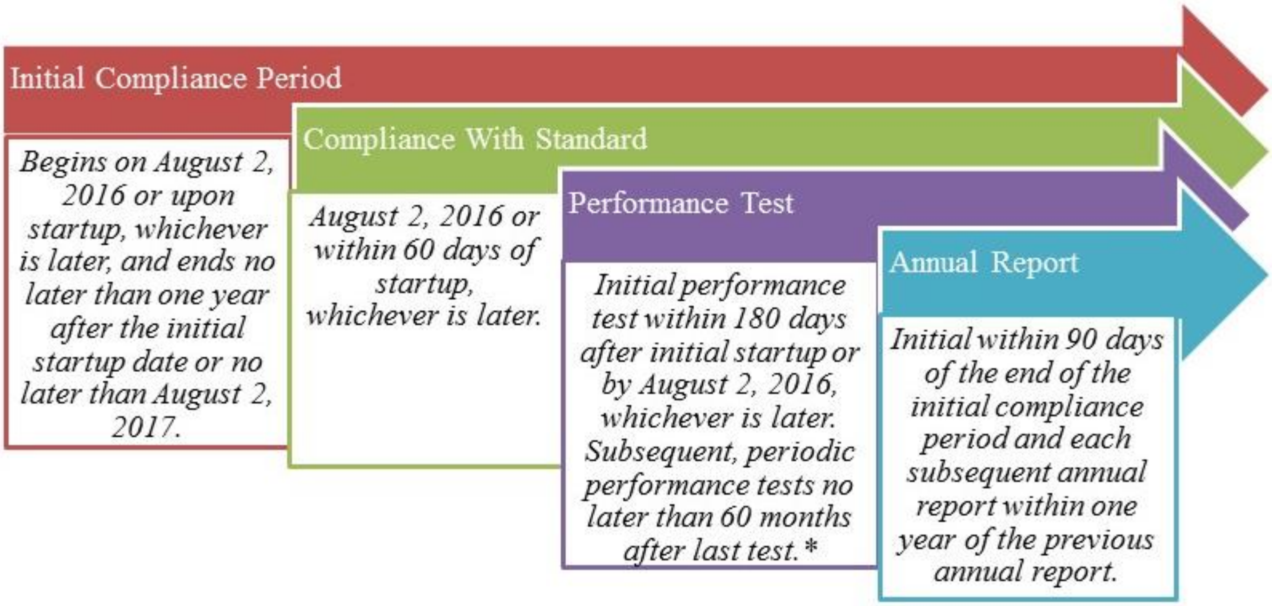
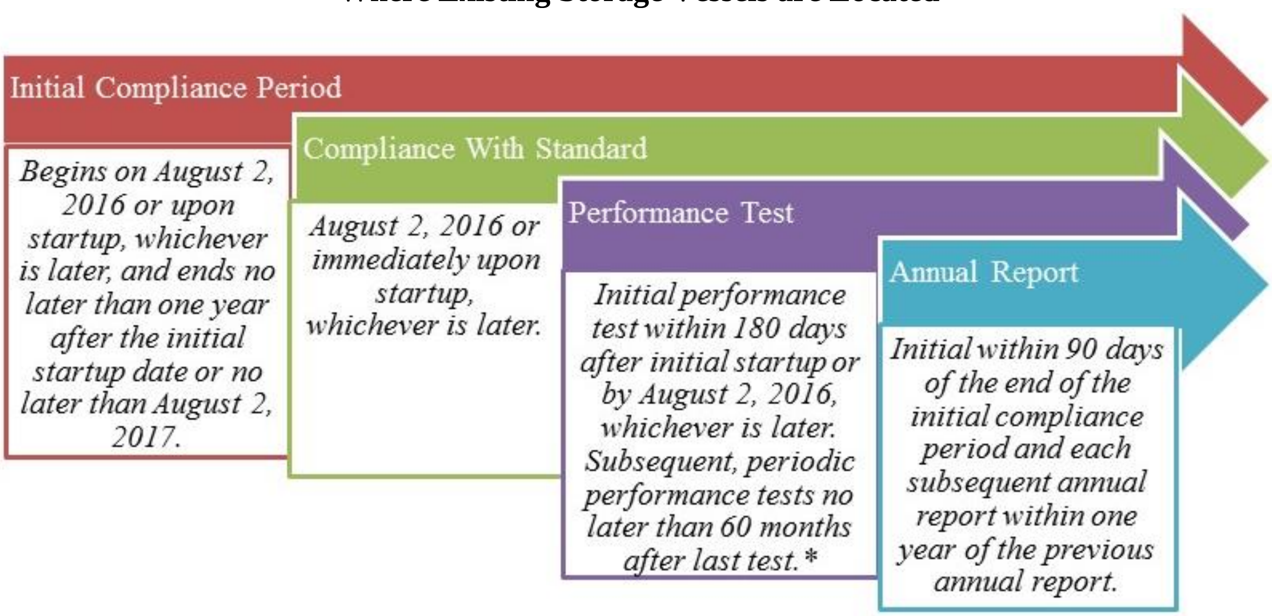


Figure 8-4. Compliance Schedule for Storage Vessels Located at a Well Site Where Existing Storage Vessels are Located



*Enclosed combustion devices that are tested by the manufacturer according to the requirements of §60.5413a(d) and that are listed on the EPA website at **www.epa.gov/airquality/oilandgas** are not subject to the periodic performance test requirements.

8.4 What testing or monitoring is required?

To meet the requirements of the 95 percent reduction in emissions from storage vessel affected facilities, you have to demonstrate that your cover meets the requirements of §60.5411a(b), your closed vent system meets the requirements of §60.5411a(b) and your control device meets the requirements of §60.5412a(c) or (d). The requirements include an initial assessment that the closed vent system is of sufficient design and capacity to accommodate all emissions from the affected facility that must be certified by a qualified professional engineer. If you use a floating roof on the storage vessel, you have to monitor it according to 40 CFR part 60, subpart Kb. The inspection and repair requirements for covers and closed vent systems are outlined in §60.5416a(c) of the rule.

You have to conduct initial and periodic performance testing and inspections of the control device as described in the rule. The performance testing requirements for control devices are outlined in §60.5413a of the rule. The inspection and repair requirements for control devices used to reduce emissions from your storage vessel affected facility are outlined in §60.5417a(h).

8.5 What, when and to whom must I report?

In addition to the information outlined in section 1.4.3 above, you must include the information outlined in §60.5420a(b)(6) of the rule in your annual report for your storage vessel affected facility.

8.6 What records must I keep?

You must maintain the records for each of your storage vessel affected facilities. Specifically, you must maintain the records outlined in §60.5420a(c)(5) through (8), (12) through (14) and (17), as applicable, for each storage vessel affected facility.

9.0 GHG and VOC Standards for Fugitive Emissions from the Collection of Fugitive Emissions Components Affected Facilities at Well Sites and Compressor Stations

9.1 How do I determine if my collection of fugitive emissions components is an affected facility?

You are subject to the fugitive monitoring requirements for the collection of fugitive emissions components in subpart OOOOa if you own or operate a crude oil or natural gas well site or a compressor station for which you commence construction, modification, or reconstruction after September 18, 2015.

> *A **well site** is one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. This includes a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).*
> *A **modification** occurs when either: a new well is drilled at your existing well site, a well at your existing well site is hydraulically fractured, or a well at your existing well site is hydraulically refractured.*

> *A **compressor station** is a site that has 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. The compressor stations are typically called "gathering and boosting", "transmission" or "storage" compressor stations.*
> *A **modification** to your compressor station occurs when an additional compressor is installed at the compressor station or when one or more compressors are replaced by compressors with a greater horsepower. If one or more compressors are replaced with compressors with equal or less horsepower, then installation of the compressors does not trigger a modification.*

9.1.1 Well site exceptions

You are not subject to the requirements in subpart OOOOa if the well site contains only one or more wellheads (i.e., the well site does not have any equipment associated with the wellheads such as separators, compressors, heaters, or dehydrators). The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads. [§60.5365a(i)(2)]

Therefore, if you add a new well, hydraulically fracture or refractured a well at your well site after September 18, 2015, you are now subject to the fugitive monitoring requirements in subpart OOOOa.

9.1.2 Compressor station exceptions

The combination of one or more compressors at a well site or located at an onshore natural gas processing plant is not a compressor station for purposes of the fugitive emission requirements. [§60.5430a]

9.2 How do I comply?

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions from the collection of fugitive emissions components at a well site or compressor station by complying with the fugitive emissions monitoring requirements outlined below. [§60.5397a introductory text]

These fugitive monitoring requirements are independent of the closed vent system and cover requirements outlined above for centrifugal compressors, reciprocating compressors, pneumatic pumps and storage vessels. [§60.5397a introductory text and §60.5411a introductory text]

> ***Fugitive emissions*** *means any visible emission from a fugitive emissions component observed using OGI or an instrument reading of 500 ppm or greater using Method 21.*
> ***Fugitive emissions component*** *means any component that has the PTE fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. 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 thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

The compliance requirements are the same for the collection of fugitive emissions components at well sites and compressor stations, with the exception of the frequency of conducting the fugitive emission monitoring surveys. The basic requirements include preparation of a fugitive emissions monitoring plan for the collection of fugitive emissions components at well sites or compressor stations within each company defined area, conducting initial and periodic monitoring, repair of any components found to be leaking, and verification (resurvey) that the repair was successful. You must also maintain records and submit annual reports of your fugitive emissions monitoring surveys. The monitoring can be conducted in-house or with a contractor, however, you are responsible for ensuring that all requirements are met when a contractor is retained to do the monitoring.

> *The collection of fugitive emissions components at all new, modified or reconstructed well sites or compressor stations are an affected facility and must meet the requirements of the fugitive emissions monitoring program.*

Figure 9-1 and **Figure 9-2** provide an overview of the emissions monitoring and repair requirements for well sites and compressor stations, respectively.

Figure 9-1. Fugitive Emissions Monitoring and Repair Requirements for the Collection of Fugitive Emissions Components at Well Sites

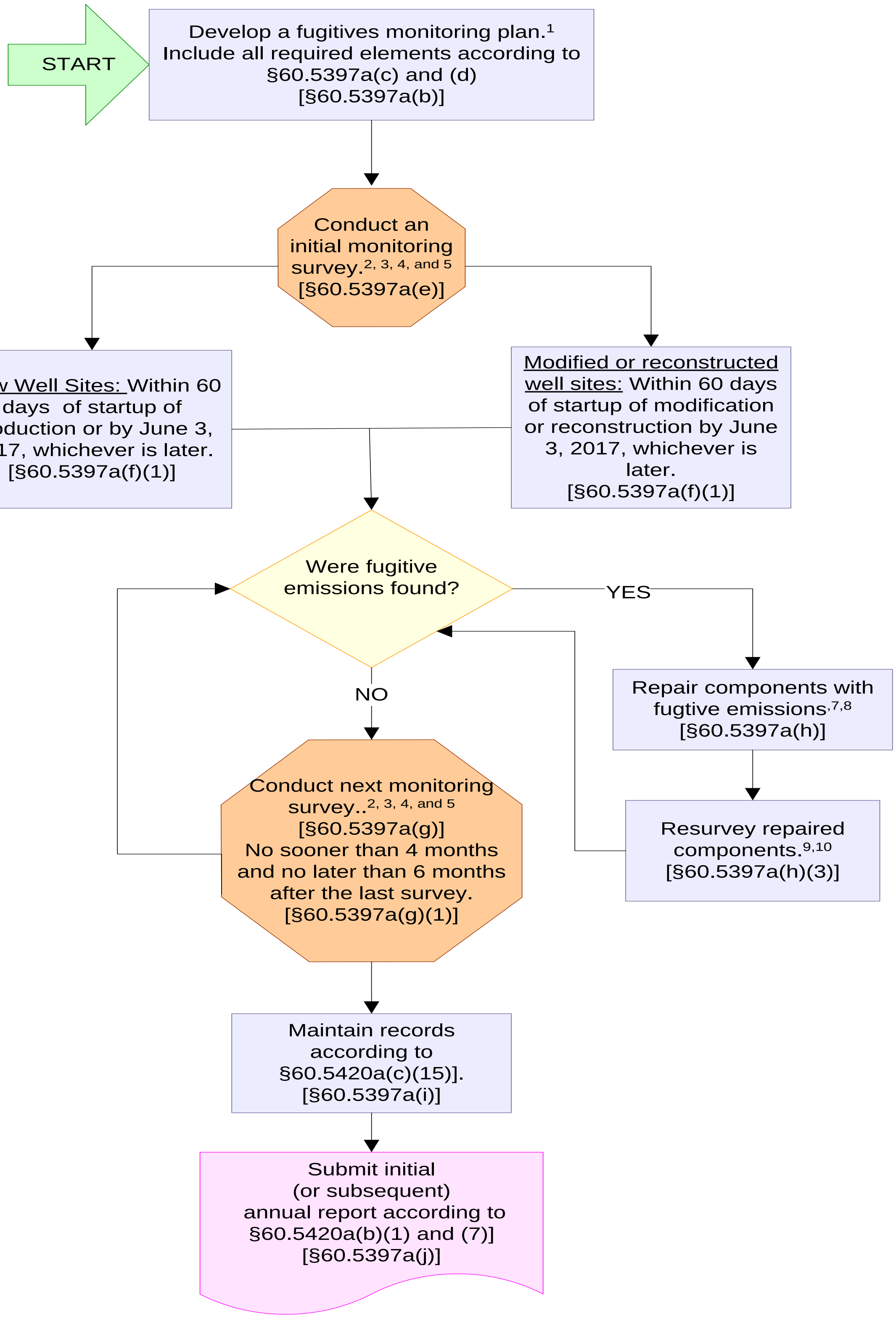
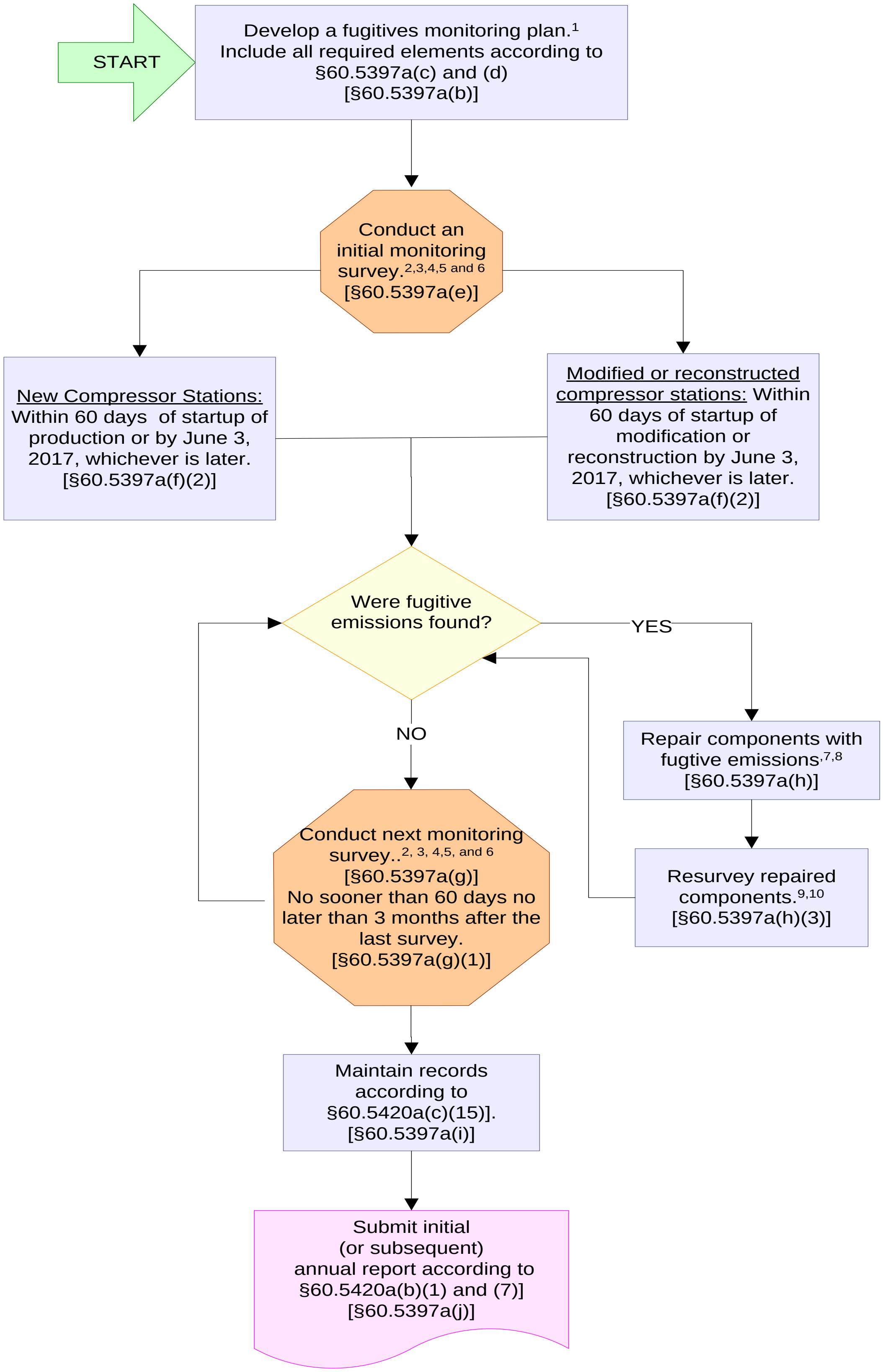


Figure 9-2. Fugitive Emissions Monitoring and Repair Requirements for the Collection of Fugitive Emissions Components at Compressor Stations



Footnotes to Emissions Monitoring and Repair Requirement Flowcharts:

1. The monitoring plan must include all information about the monitoring equipment and Quality Assurance Procedures for monitoring equipment. [§60.5397a(c)]

2. You must use an OGI camera or a Method 21 approved portable analyzer to conduct the monitoring survey. [§60.5397a(a)]

3. The rule provides special provisions for monitoring fugitive emissions components that are difficult or unsafe to monitor. [§60.5397a(g)(3) and (4)]

4. Covers and closed vent systems subject to monitoring and repair under other sections of the rule are not subject to these requirements)). [§60.5397a(h)]

5. For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture). [§60.5397a(h)(3)(ii)]

6. If a collection of fugitive emissions components at a compressor station is located within an area that has an average calendar month temperature below 0 Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period, fugitive emissions monitoring may be waived for that quarter. Fugitive emissions monitoring may not be waived for two consecutive quarterly monitoring periods. [§60.5397a(g)(5)]

7. Each leaking component must be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. [§60.5397a(h)(1)]

8. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. [§60.5397a(h)(2)]

9. Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, to ensure that there are no fugitive emissions. [§60.5397a(h)(3)]

10. 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 OGI within 30 days of finding such fugitive emissions. [§60.5397a(h)(3)(i)]

Whether you or your contractor perform fugitive monitoring, your monitoring plan must include the information and quality assurance procedures for the equipment used. Be sure to have the contractor provide the information for inclusion into your monitoring plan.

If monitoring is conducted in-house, include names and certifications or training of individuals that can conduct the monitoring. If a contractor is used, specify minimum training and experience required to qualify to conduct the surveys. And after a contractor *is used, ensure that their report includes qualifications of surveyors.*

9.3 When must I comply?

You must have your monitoring plan for each company-defined area in place and perform the **initial monitoring survey** within 60 days of the startup of production for new, modified or reconstructed well sites or within 60 days of the startup of a new, modified or reconstructed compressor station or by June 3, 2017, whichever is later.

The initial monitoring survey must take place by June 3, 2017 or within 60 days of the startup of production, whichever is later.

The *startup of production* for a well site is 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.

For **well sites**, subsequent monitoring surveys must be performed **semiannually** after the initial survey. The semiannual surveys must be at least four (4) months apart.

Quarterly fugitive emissions monitoring surveys at compressor stations are waived if, based on three years of historical climatic data, two of the three consecutive months within the quarter have an average temperature below 0°Fahrenheit.

For **compressor stations**, subsequent monitoring surveys must be performed **quarterly** after the initial survey. The quarterly surveys must be at least 60 days apart.

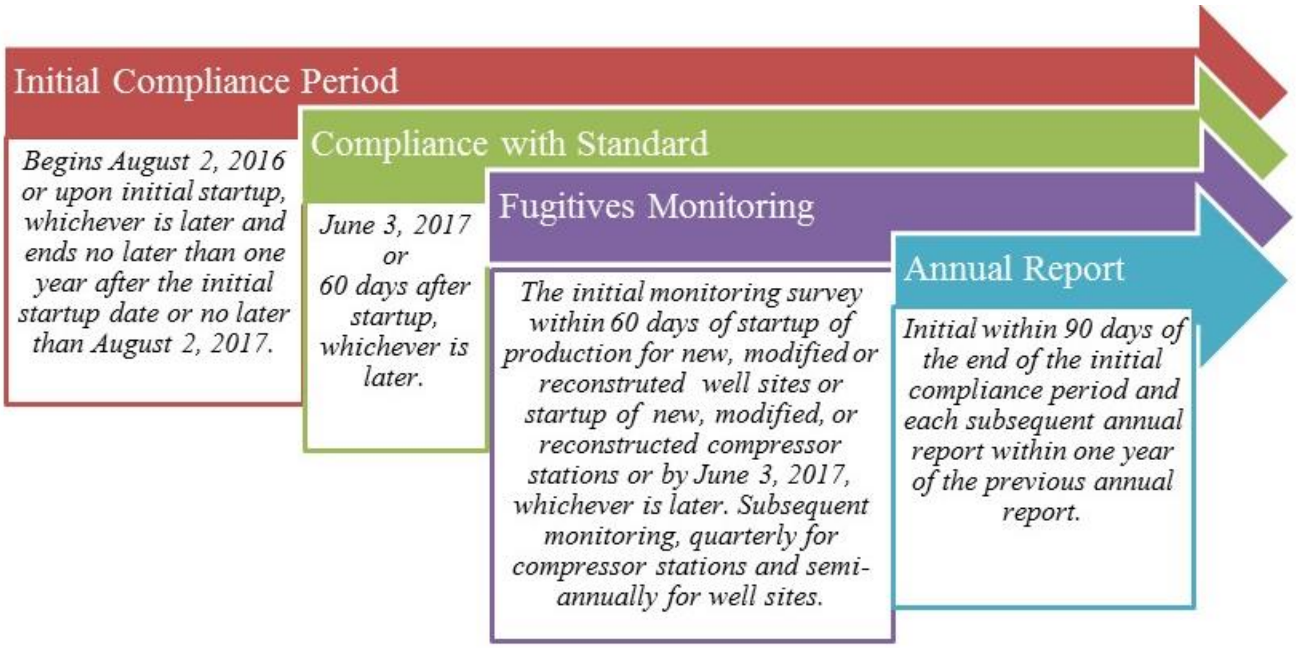
Except as noted in section 9.3 above, you must repair or replace each identified leaking fugitives emissions component as soon as practicable, but no later than 30 calendar days after detection of fugitive emissions.

You must resurvey each repaired fugitive emission component as soon as practicable after repair, but not later than 30 days after repair.

You must submit your initial annual report within 90 days of the end of the initial compliance period which begins August 2, 2016 or upon startup, whichever is later, and ends no later than one year after the initial startup date or no later than August 2, 2017.

Figure 9-4 provides an overview of the compliance schedule for your well sites and compressor stations.

Figure 9-3. Compliance Schedule for the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations



9.4 What testing or monitoring is required?

There are no testing requirements associated with these standards. The fugitive emissions monitoring standard described above includes all monitoring required by the rule for the collection of fugitive emissions components at well sites and compressor stations.

The NSPS includes a process for the agency to permit the use of innovative technology for monitoring the collection of fugitive emissions components at well sites and/or compressor stations through the use of an alternative means of emission limitation. [§60.5398a].

9.5 What, when and to whom must I report?

In addition to the information outlined in 1.4.3 above, you must include the information outlined in §60.5420a(b)(7) of the rule in your annual report for your fugitive emissions monitoring surveys.

9.6 What records must I keep?

You must maintain the records for each fugitive emissions monitoring survey. Specifically, you must maintain the records outlined in §60.5420a(c)(15), as applicable, for the collection of fugitive emissions components at well site or compressor station vessel affected facilities within each company-defined area.

The records that must be kept for the collection of fugitive emissions components at well sites and compressor stations are the same. You must maintain a copy of the monitoring plan (as described above) either onsite or at the nearest field office. [§60.5420a(c)]

In addition to the monitoring plan, you must maintain records of each fugitive emissions monitoring survey conducted either onsite or at the nearest field office for at least five years. Also, for the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived. [§60.5420a(c)(15)]]

10.0 GHG and VOC Standards for Equipment Leaks at Onshore Natural Gas Processing Plants

10.1 How do I determine if my group of equipment is an affected facility?

The GHG and VOC standards for equipment leaks at natural gas processing plants apply to the group of all equipment (except single compressors) within a process unit that is located at an onshore natural gas processing plant and that commenced construction, reconstruction or modification after September 18, 2015. [§60.5365(f)] Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit that is located at an onshore natural gas processing plant is also an affected facility. [§60.5365(f) and (f)(2)]

Equipment*, as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form 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.*

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.*

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.*

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.*

Onshore *means all facilities except those that are located in the territorial seas or on the outer continental shelf.*

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.*

Exceptions to this include:

- Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure. This change is not by itself considered a modification and therefore, is not subject to the rule. [§60.5365(f)(1)]
- Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of the rule. [§60.5365(f)(2)]
- The equipment within a process unit of an affected facility located at onshore natural gas processing plants as described above if they are subject to and controlled according to 40 CFR part 60 subparts VVa, GGG, or GGGa. [§60.5365(f)(3)]

10.2 How do I comply?

The equipment leaks standard for equipment at natural gas processing plants establish a LDAR program that reflects the procedures and leak thresholds established in the NSPS for Equipment Leaks of VOCs in the Synthetic Organic Chemicals Manufacturing Industry (40 CFR part 60, subpart VVa). Subpart VVa establishes leak definitions and monitoring frequencies for equipment, such as valves, connectors, pumps, pressure relief devices and open-ended valves or lines.

Subpart OOOOa is based on adopting several of the provisions from subpart VVa with additional provisions for exceptions and requirements. The LDAR program requires monitoring of equipment using Method 21 or sensory monitoring, when permissible, repair of leaking equipment and resurvey of equipment to ensure success of the repair. **Figure 10-1** provides an overview of the specific sections of 40 CFR part 60, subparts VVa and OOOOa that apply to equipment leaks at natural gas processing plants.

Continuous compliance is demonstrated by meeting all of the requirements of §60.5400a.

10.3 When must I comply?

You must comply with the GHG and VOC emission reduction standards for equipment leaks at natural gas processing plant, as specified in §60.5400a(a). Compliance with the LDAR requirements must be demonstrated within 180 days of initial startup as specified at §60.482-1a(a) and (d), except for connectors which must be demonstrated within 12 months after initial startup (§60.482-11a(a)). Note that the "within 180 days" timeframe applies to the full suite of compliance activities required by the rule, including those which must begin upon startup (e.g., monthly monitoring) and those not due for 180 days (performance testing of any control devices). You must submit your first annual report within 90 days after the end of the initial compliance period, which begins on August 2, 2016 or upon startup date of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017.

Figure 10-2 provides an overview of the compliance schedule for equipment leaks at natural gas processing plants

Figure 10-1. Subpart OOOOa Requirements for Groups of Equipment in Processing Units at Onshore Natural Gas Processing Plants (Equipment Leaks)

START

Group of all equipment, except compressors, within a process unit is an affected facility [§60.5365a(f) and §60.5400a]

Meet the monitoring and repair requirements for an LDAR Program per 40 CFR part 60 , subpart VVa with exceptions as outlined in §60.5401a. [§60.5400a], including complying with;

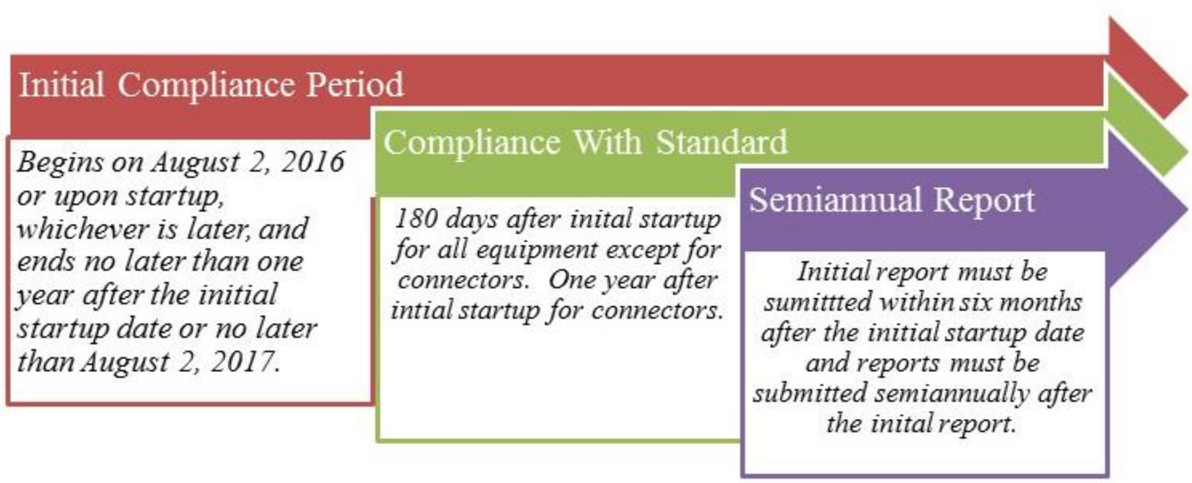
- §60.482-1a(a), (b) and (d) General.
- §60.482-2a Standards: Pumps in light liquid service.
- §60.482-4a Standards: Pressure relief devices in gas/vapor service.
- §60.482-6a Standards: Open-ended valves or lines.
- §60.482-7a Standards: Valves in gas/vapor service and in light liquid service.
- §60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.
- §60.482-9a Standards: Delay of repair.
- §60.482-10a Standards: Closed vent systems and control devices.
- §60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.

Exceptions to the above subpart VVA provisions are outlined in §60.5400a(f) and §60.5401a. [§60.5400a]

And:

- Conduct performance testing and monitoring according to the test methods and procedures outlined in §60.485a [§60.5400a(d)]
- Maintain records according to the requirements of §60.486a and §60.5421a(b). [§60.5400a(e)]
- Submit semi-annual reports according to the requirements outlined in §§60.487a(a), (b), (c)(2)(i) through (iv), (c)(2)(vii) through (viii) and §60.5422a(a) through (c). [§60.5400a(e)]

Figure 10-2. Compliance Schedule for Equipment Leaks at Onshore Natural Gas Processing Plants



10.4 What testing or monitoring is required?

The rule requires use of Method 21 for monitoring and identification of leaks and for resurvey after repair. The specifics of all applicable test methods and procedures are outlined in 40 CFR part 60, subpart VVa, §60.485a.

10.5 What, when and to whom must I report?

You must submit reports for equipment leaks affected facilities at onshore natural gas processing plants. Subpart OOOOa (§60.5400a(e)) references §60.487a and §60.5422a for the equipment leaks reporting requirements, which require the submission of semiannual reports. The semiannual reports must be submitted using CEDRI (accessed via the EPA's CDX).

10.6 What records must I keep?

You must maintain records for each affected facility subject to GHG and VOC requirements for equipment leaks at onshore natural gas processing plants according to §60.486a of subpart VVa and §60.5421a(b) of subpart OOOOa.

11.0 Sulfur Dioxide Standards for Sweetening Units at Onshore Natural Gas Processing Plants

11.1 How do I determine if my sweetening unit is an affected facility?

The standards for sweetening units located at onshore natural gas processing plants apply to each sweetening unit that process natural gas or each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility. [§60.5365a(g)(1 and 2)]

Sweetening units that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas are required to comply only with recordkeeping and reporting requirements outlined in §60.5423a(c) and have no control or emission reduction requirements. [§60.5365a(g)(3)]

Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are exempt from the rule requirements. [§60.5365a(g)(4)]

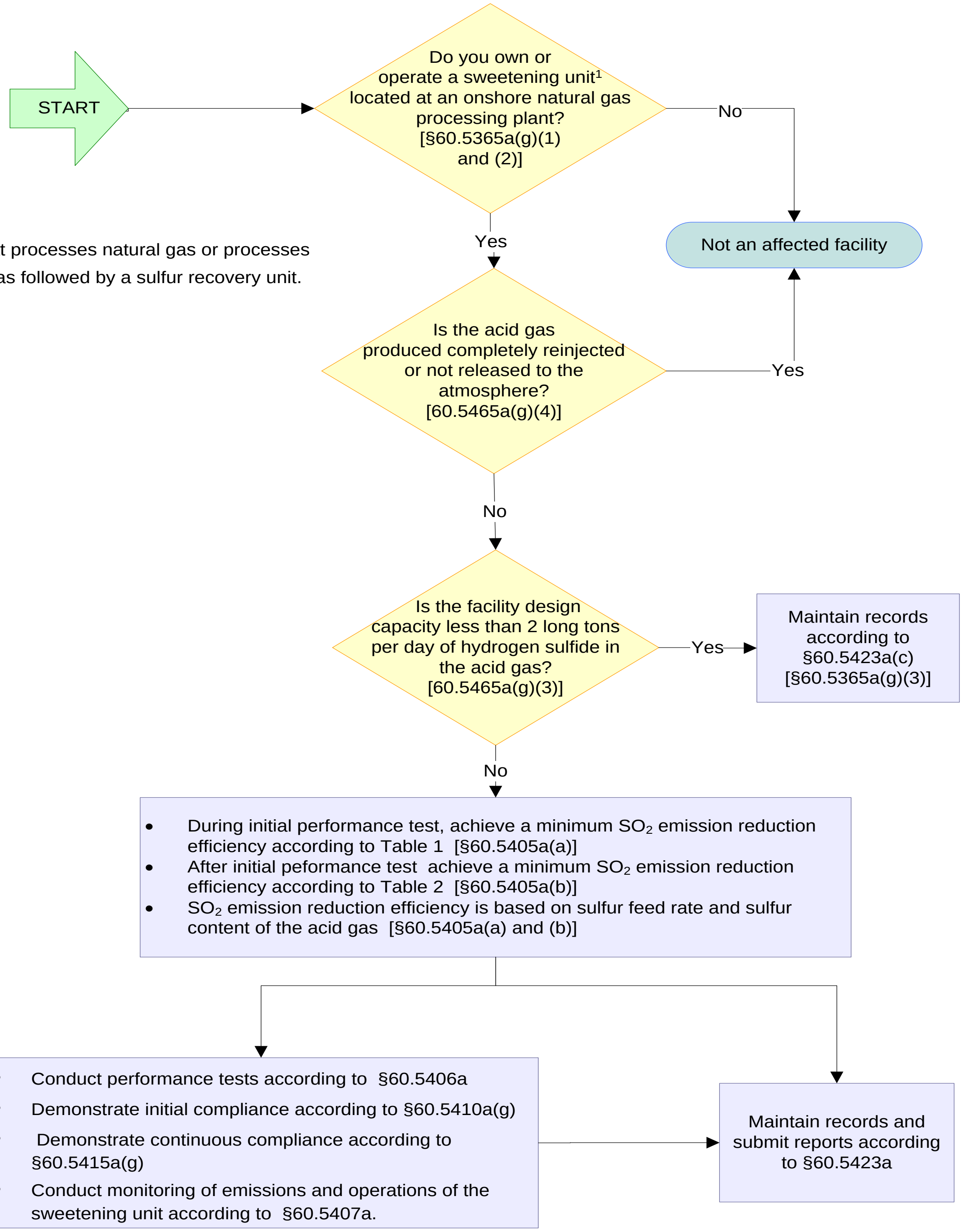
11.2 How do I comply?

To demonstrate initial compliance with the standard for sweetening units at onshore natural gas processing plants, you must demonstrate during the initial performance test, as required by §60.8(b), that the equipment achieves a minimum SO_2 emission reduction efficiency outlined in Table 1 of the rule. The emission reduction efficiency is based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility. [§60.5405a(a)] You must conduct performance testing and determine initial compliance for your sweetening unit according to methods and procedures outlined in §60.5406a.

After demonstrating initial compliance with the provisions of §60.5405a(a), you must operate the sulfur recovery unit such that you achieve at a minimum SO_2 emission reduction efficiency as outlined in Table 2 of the rule. [§60.5405a(b)] You must monitor the emissions and operation of the sweetening unit affected facilities and determine ongoing compliance according to the procedures outlined in 60.5407a. [§60.5407a(a)] You demonstrate continuous compliance using the procedure outlined in §60.5415a(g).]

Figure 11-1 provides an overview of the applicable requirements for your sweetening unit affected facility.

Figure 11-1. Subpart OOOOa Requirements for Sweetening Units at Onshore Natural Gas Processing Plants



Footnote:

1. Unit that processes natural gas or processes natural gas followed by a sulfur recovery unit.

__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.

__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.

__Sulfur recovery unit__ means a process device that recovers elemental sulfur from acid gas.

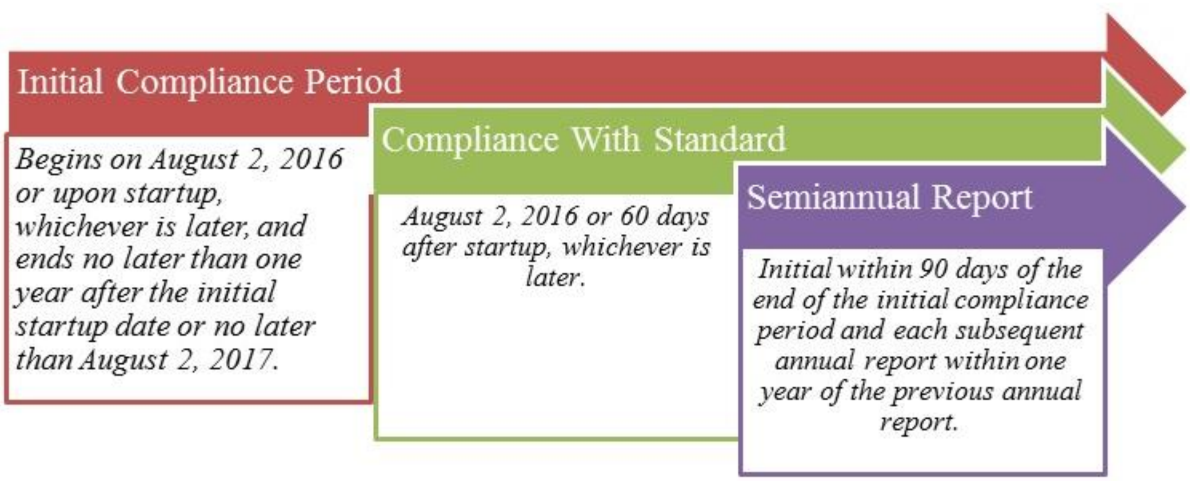
__Sweetening unit__ means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

11.3 When must I comply?

You must demonstrate initial compliance according to §60.5405a(a) and 60.5410a(g) by August 2, 2016 or 60 days after startup, whichever is later. You must submit your first annual report within 90 days after the end of the initial compliance period, which begins on August 2, 2016 or upon startup date of the affected facility, whichever is later, and ends no later than one year after the initial startup date for the affected facility or no later than August 2, 2017. [§60.5410a introductory text]

Figure 11-2 provides an overview of the compliance schedule for sweetening units located at onshore natural gas processing plants.

Figure 11-2. Compliance Schedule for Sweetening Units at Onshore Natural Gas Processing Plants



11.4 What testing or monitoring is required?

You must conduct performance testing according to the requirements outlined in §60.5406a and monitoring of your sweetening unit according to the requirements outlined in §60.5407a.

11.5 What, when and to whom must I report?

For each sweetening unit affected facility, you must submit annual report as outlined in §60.5423a(b). The reports must be submitted using CEDRI (accessed via the EPA's CDX).

11.6 What records must I keep?

For each sweetening unit affected facility you must maintain records as outlined in §60.5423a(a) and (c) through (e).

12.0 Overview of Who Implements and Enforces the Rule and How to Report Violations

12.1 Who implements and enforces the rule?

The EPA is responsible for implementation of this rule and its enforcement. In fact, there are certain aspects of this rule that EPA may not delegate. The following authorities rest solely with the EPA:

1. Approvals of alternative or equivalent test methods (§60.8(b)(2) and (b)(3)).
2. Equivalency determinations (§60.5389a and §60.5402a).

> ***Delegate*** *means that EPA grants authority to another entity (e.g. state, local or tribe) to carry out the requirements of the rule. Under such delegations, EPA still retains their own authorities.*

However, the EPA may delegate implementation and enforcement authority to a state, local or tribal authority upon request. Any provisions of NSPS OOOOa, not noted above, may be delegated.

Finally, it should be noted that this compliance guide explains your federal compliance obligations with respect to this NSPS federal rule. There may be other state or local requirements that apply to you which are different from, or more stringent than, the federal requirements described in this guide.

12.2 What must I do in the event of a potential violation?

Assuring compliance with our nation's environmental laws is one of the EPA's primary commitments. In carrying out this responsibility, we use many different approaches. One approach is to seek help from you by asking you to provide the EPA with information about potentially harmful environmental activities in your communities and workplaces. Reports from the public have led to state and federal enforcement cases and ultimately served environmental protection well. We invite you to help us protect our nation's environment by identifying and reporting environmental violations. The **EPA's Report an Environmental Violation** website provides a way for you to report suspected environmental violations. Violations may take many different forms. Some are done intentionally and may be criminal violations. For more information on environmental crimes, please see **Violations Types and Examples** on our website.

As noted above in section 12.1, certain enforcement authorities under this rule may have been delegated to State, local or tribal authorities. If this is the case in your State, you also should contact these State, local or tribal authorities in the event of a violation.

If the potential violation is your own and you would like further information regarding how to ensure compliance, you should contact the EPA through the appropriate EPA officials listed in section 13.1 under *Who can I contact if I have questions or need further assistance*? You may also contact OECA's lead for oil and gas compliance, Marcia Mia, by mail at Office of Compliance, U.S. Environmental Protection Agency, Mail Code 2223A, 1200 Pennsylvania Ave., NW, Washington, DC

20460; email at **mia.marcia@epa.gov**; or phone at 202-564-7042. Finally, you may also contact your delegated (state/local/tribal) authority.

13.0 More Information for Further Assistance

13.1 Who can I contact if I have questions or need further assistance?

For questions about this final rule for the oil and natural gas sector contact Ms. Lisa Thompson at the Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143-05), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541-9775; email address **thompson.lisa@epa.gov.**

For additional assistance at the EPA regional level, the following region-specific EPA personnel may also be contacted at the Regional Offices:

- Region 1 – Steve Rapp at rapp.steve@epa.gov;
- Region 2 – Christine Ash at ash.christine@epa.gov;
- Region 3 – Chip Hosford at Hosford.chip@epa.gov or Bruce Augustine at augustine.bruce@epa.gov;
- Region 4 – Denis Kler at kler.denis@epa.gov;
- Region 5 – Natalie Topinka at Topinka.natalie@epa.gov;
- Region 6 – Cynthia Kaleri at Kaleri.cynthia@epa.gov;
- Region 7 – Robert Cheever at Cheever.robert@epa.gov;
- Region 8 – Scott Patefield, at Patefield.scott@epa.gov;
- Region 9 – David Bassinger at bassinger.david@epa.gov; and
- Region 10 – John Keenan at keenan.john@epa.gov.

To determine which region your state is located in, please refer to the Map of EPA Regions provided **https://www.epa.gov/aboutepa**.

13.2 Where can I find the rulemaking and related documents?

- The final "Oil and Natural Gas Sector: Reconsideration of Remaining Provisions of the New Source Performance Standards " rulemaking (81 FR 35823**,** June 3, 2016) is available as a Federal Register document at **https://www.federalregister.gov/articles/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources**.
- All rulemaking documents and information, including background data and analyses, regarding this rulemaking can be found in Docket ID EPA-HQ-OAR-2010-0505 on Regulations.gov at **https://www.regulations.gov/docket?D=EPA-HQ-OAR-2010-0505.**
- Supporting technical information for the final rule can be found in the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Background Technical Support Document for the Final New Source Performance Standards, 40 CFR Part 60, subpart OOOOa, May, 2016" which can be found in the docket, EPA Docket ID: EPA-HQ-OAR-2010-0505-7631.

13.3 What is the compliance assurance process?

An effective environmental protection system requires a strong and vigorous enforcement program. OECA has striven to protect human health and the environment. Using an appropriate combination of enforcement and compliance assistance, we and our partners prevent and reduce pollution, thereby protecting human health and the environment.

Compliance monitoring is one of the key components EPA uses to ensure that the regulated community obeys environmental laws and regulations. It encompasses all regulatory agency activities performed to determine whether a facility (or group of facilities, such as plants related geographically, by sector, or corporate structure) is in compliance with applicable law. Compliance monitoring includes:

- Formulation and implementation of compliance monitoring strategies
- Onsite compliance monitoring: compliance inspections, evaluations, and investigations (including review of permits, data, and other documentation)
- Off-site compliance monitoring: data collection, review, reporting, program coordination, oversight, and support
- Inspector training, credentialing and support

Inspections are an integral part of EPA's compliance monitoring programs. They are an important tool for officially assessing compliance with environmental regulations and requirements. EPA and its regulatory partners conduct compliance inspections under the majority of statutory and regulatory program authorities.

Inspections are visits to a facility or site for the purpose of gathering information to determine whether it is in compliance. Inspections generally include pre-inspection activities such as obtaining general site information before entering the facility or site. Other activities that may be conducted during the onsite visit include:

- Interviewing facility or site representatives,
- Reviewing records and reports,
- Taking photographs,
- Collecting samples, and
- Observing facility or site operations.

The intensity and scope of an inspection can range from a quick walk-through inspection that takes less than half a day, to an inspection with extensive physical sample collection that can take weeks to complete.

The EPA provides compliance incentives and auditing to encourage facilities to find and disclose violations to the Agency. The EPA has developed the Small Business Compliance Policy which promotes environmental compliance among small businesses (those with 100 or fewer employees) by providing incentives to discover and correct environmental problems. EPA will eliminate or significantly reduce penalties for small businesses that voluntarily discover violations of environmental law and promptly disclose and correct them. The Policy accomplishes this in two ways: by setting forth guidelines for the Agency to apply in reducing or waiving penalties for small businesses that come forward to disclose and make good faith efforts to correct violations, and by deferring to State, local and Tribal governments that offer these incentives. A copy of this policy can be found at **https://www.gpo.gov/fdsys/pkg/FR-2000-04-11/pdf/00-8955.pdf.** For businesses with more than 100 employees, we have the "EPA Audit Policy" **(**available at **https://www.gpo.gov/fdsys/pkg/FR-2000-04-11/pdf/00-8954.pdf)** formally entitled, "Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations."

The EPA will eliminate or reduce the gravity component of civil penalties against small businesses based on the following criteria:

- Discovery is voluntary (i.e., the small business discovers a violation on its own before an EPA or State inspection). These violations can be discovered after receiving compliance assistance, conducting an environmental audit or participating in mentoring programs. Other activities that may be useful in discovering violations include establishing CMS, using compliance checklists, reading materials on complying with environmental requirements, using compliance assistance center web sites, and attending training classes. The violation must be identified voluntarily, and not through a monitoring or sampling requirement prescribed by statute, regulation, permit, judicial or administrative order, or consent agreement.
- Violations must be disclosed fully and in writing to the EPA or the State within 21 calendar days after the small business has discovered that the violation has occurred, or may have occurred. Prompt disclosure is evidence of the small business's good faith in wanting to achieve or return to compliance as soon as possible. Good faith also requires that a small business cooperate with the EPA and in a timely manner provide such information requested by the EPA to determine applicability of this Policy.

"Promptly disclosed" -*"In order to be considered "prompt" under both the Audit Policy and Small Business Compliance Policy, potential violations must be disclosed online within 21 calendar days of the regulated entity's discovery that such potential violations may have occurred. If the 21st day after discovery falls on a weekend or federal holiday, the eDisclosure system will treat the disclosure as prompt if it is submitted on the next business day."*

"Discovery"*: Discovery is when any officer, director, employee or agent of the facility has an objectively reasonable basis for believing that a violation has, or may have occurred"*

- The business corrects the violation within the shortest practicable period of time. Correcting the violation includes remediating any environmental harm associated with the violation, as well as putting into place procedures to prevent the violation from happening again.
  - For any violation that cannot be corrected within 90 calendar days of its discovery, the small business must submit a written schedule, or the agency may, at its sole discretion, elect to issue a compliance order with a schedule, as appropriate. The small business must correct any violations within 180 calendar days after the date that they were discovered.

- If the small business intends to correct the violation by putting into place pollution prevention measures, the business may take an additional period of up to 180 calendar days, i.e., up to a period of 360 calendar days from the date the violation is discovered.

As of December 9, 2015, the EPA modernized the implementation of its violation self-disclosure policies by creating a centralized web-based “electronic self-disclosure (eDisclosure)” portal to receive and automatically process self-disclosed civil violations of environmental law. Under the automated system, large and small businesses will quickly be able to get some of their more routine types of disclosures resolved. More information may be found at the EPA eDisclosure web page. In general, in order to submit an eDisclosure you must first register with the EPA’s CDX system. Then you submit a voluntary prompt disclosure and within 60 days submit a Compliance Certification in the eDisclosure system.

Please visit our Audit Policy page on the web for more information or contact the following Audit Policy Contacts:

For civil violations in more than one EPA Region or questions about the Audit Policy:

Contact: Philip Milton at milton.philip@epa.gov

Regional Contacts:

Region 1 – Diane Boudrot at boudrot.diane@epa.gov
Region 2 – Nester Louis at louis.nester@epa.gov
Region 3 – Samantha Beers at beers.samantha@epa.gov
Region 4 – Sheila Hollimon at hollimon.sheila@epa.gov
Region 5 – Jodi Wilson at wilson.jodi@epa.gov
Region 6 – Marcia Moncrieffe at moncrieffe.marcia@epa.gov
Region 7 - Julie Murray at murray.julie@epa.gov
Region 8 – David Rochlin at Rochlin.davide@epa,gov
Region 9 – Daniel Reich at reich.daniel@epa.gov
Region 10 – Edward Kowalski at Kowalski.edward@epa.gov

To determine which region your state is located in, please refer to the Map of EPA Regions provided on the following the EPA webpage - **https://www.epa.gov/aboutepa**.

13.4 If the Agency discovers a violation, what might be its response?

To maximize compliance, the EPA implements a balanced program of compliance assistance, compliance incentives, and traditional law enforcement. The EPA knows that small businesses which must comply with complicated new statutes or rules often want to do the right thing, but may lack the requisite knowledge, resources, or skills. Compliance assistance information and technical advice helps small businesses to understand and meet their environmental obligations. As discussed previously, the EPA uses a variety of methods to determine whether businesses are complying, including inspecting facilities, reviewing records and reports, and responding to citizen complaints. If we learn a person is violating the law, the EPA (or a State, if the program is delegated) may file an enforcement action seeking penalties of up to 93,750, per violation, per day. The proposed penalty in a given case will depend on many factors, including the number, length, and severity of the violations, the economic benefit obtained by the violator, and its ability to pay. The EPA has policies in place to ensure penalties are calculated fairly. These policies are available to the public and may be found at **https://www.epa.gov/enforcement/policy-guidance-publications#models.**

In addition, any company charged with a violation has the right to contest the EPA's allegations and proposed penalty before an impartial judge or jury.

In summary, the EPA recognizes that we can achieve the greatest possible protection by encouraging small businesses to work with us to discover, disclose, and correct violations. That is why we have issued self-disclosure, small business, and small community policies to eliminate or reduce penalties for small and large entities which cooperate with the EPA to address compliance problems.

13.5 What is the legal status of this guide?

- A judge can look at a compliance guide in determining what penalty is appropriate and reasonable, although the content of the guide cannot otherwise be reviewed by the court.
- In this Compliance Guide, we have tried to make clear what you must do to comply with the applicable law and regulation. This is the minimum required by SBREFA. You'll notice, however, that we have also included suggestions for alternative approaches that may make compliance easier and possibly even reduce costs. We hope you find this presentation of regulatory requirements useful and the additional information helpful in reaching and maintaining compliance.

13.6 How do I minimize harm if I think I am out of compliance?

If you believe that you are out of compliance or have some doubt as to the existence of a violation, EPA recommends that the business make a prompt disclosure and allow the regulatory authorities to make a definitive determination. This will ensure that the small business meets the disclosure period requirement. In the meantime, you can do one or more of the following options to stop or minimize emissions from the source:

- Stop or bypass the equipment or process that you believe is out of compliance so that emissions are no longer be emitted,
- Reduce the production rate of the process or throughput of the equipment to minimize the emissions from that source.

13.7 What is pollution prevention and how can it affect my operations?

Pollution prevention is any practice that reduces, eliminates, or prevents pollution at its source. The prevention of pollution means less hazards posed to public health and the environment. Pollution prevention approaches can be applied to all pollution-generating activities, including many found in the oil and natural gas sector. These approaches include: increasing efficiency in energy use and use of environmentally benign fuel sources, modifying a production process to produce less waste, using non-toxic or less toxic chemicals as cleaners, degreasers and other maintenance chemicals and implementing water and energy conservation practices.

A source of pollution prevention practices can be found at Natural Gas STAR (**https://www3.epa.gov/gasstar/index.html**). Natural Gas STAR provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. Through this work, the oil and natural gas industry, in conjunction with Natural Gas STAR, has pioneered some of the most widely used, innovative technologies and practices that reduce methane emissions.

- Discuss pollution prevention and its benefits, including how it may be used to help a facility/operation save money and/or possibly avoid regulation.
- To the extent that there are other pollution prevention opportunities, including those which may make good business sense or could exempt a small entity from certain requirements, the program, with support from Office of Pollution Prevention and Toxics (OPPT), has the option to expand this section and include this information.

13.8 How useful was this guide?

The EPA is continually striving to improve outreach to regulated entities and the public. Please let us know how useful this guide was to you, including its readability and suggestions you may have for improvements. You may direct all feedback to Ms. Lisa Thompson at the Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143-05), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541-9775; email address: **thompson.lisa@epa.gov**.

Appendix A

Conducting A Low Pressure Well Determination

A.1 How do I determine if my well is a low pressure well?

Instead of using the low pressure well equation, under the final rule, operators who suspect that a well may be a low pressure well have the option, for screening purposes, of performing a wellhead static pressure (i.e., pressure with the well shut in and not flowing) check following fracturing and prior to the onset of flowback.

Low pressure wells have specific requirements under the rule. Therefore, you will need to determine if your well meets the definition of low pressure well to determine the requirements for the well. As with all determinations conducted for compliance under the rule, you must maintain records of all input data, calculations or other pertinent information supporting the outcome of your low pressure well determination. The specific records are noted in the Recordkeeping section below. **Figure A-1** provides a schematic of the process of determining if your well is a low pressure well.

You must determine, in advance of the start of flowback, whether your well is a low pressure well in order to apply the appropriate requirements to the well completion operation.

The definition of a low pressure well as provided in §60.5430a is:

Low pressure well means a well that satisfies at least one of the following conditions:

- The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter;
- The pressure of flowback fluid immediately before it enters the flow line, as determined under §60.5432a, is less than the flow line pressure at the sales meter; or
- Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Under the final rule, your well qualifies as a low pressure well if it meets any <u>one</u> of the above conditions. Each of these conditions is explained further below.

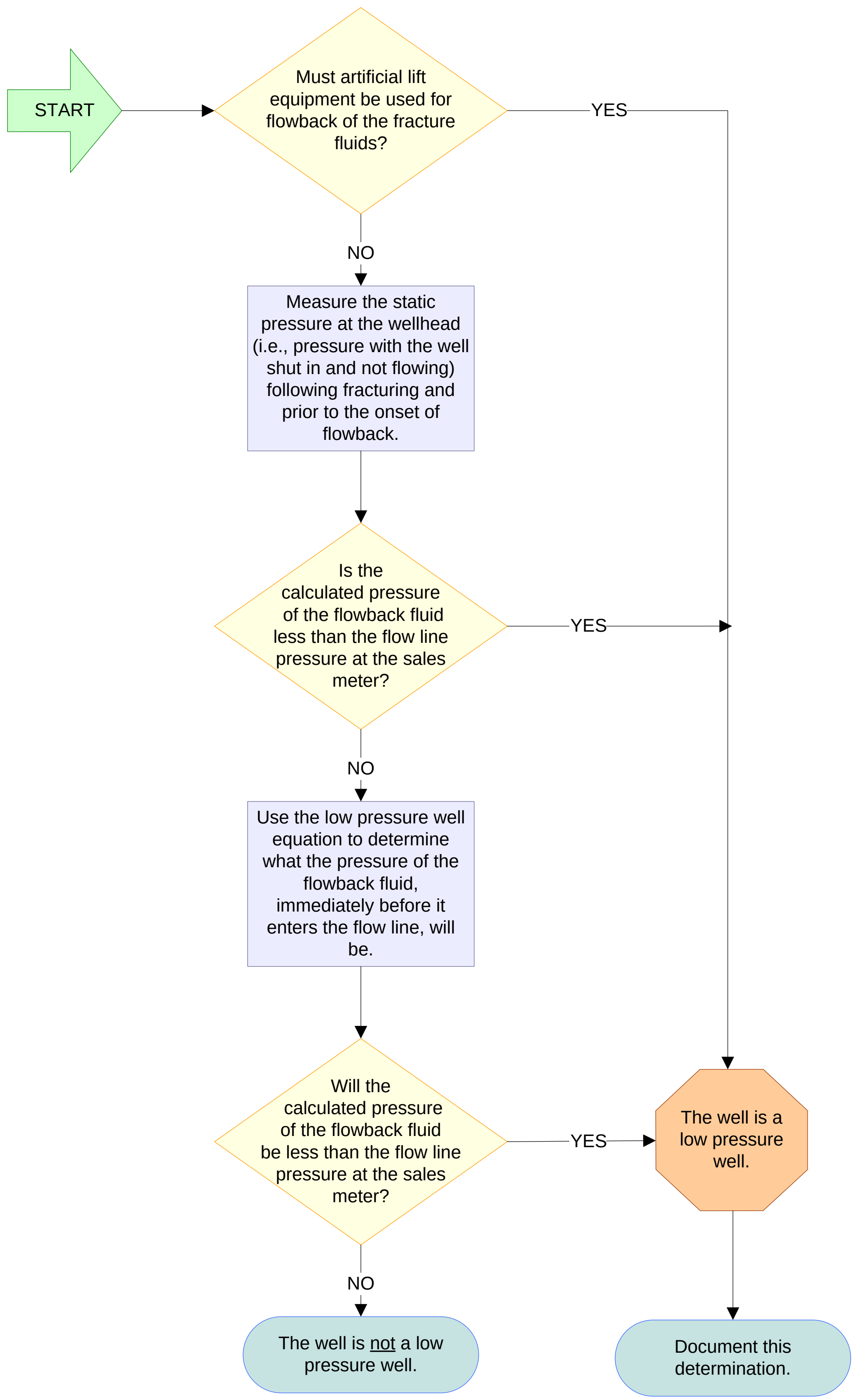
<u>Use of Artificial Lift Equipment</u>

Wells that require artificial lift equipment for flowback of fracture fluids should be classified as low pressure wells, as we believe that performing a REC is technically infeasible for these wells.

If you must use artificial lift equipment at your well to lift the fracture fluids to the surface, the well qualifies as a low pressure well. You will need to keep a record to document that this is the case and submit that documentation in the initial annual report for the well [§60.5420a(b)(2)(iii) and §60.5420a(c)(1)(vii)]

If you do not need to use artificial lift equipment for flowback, your well still may qualify as a low pressure well based on the static pressure at the wellhead. The next section explains how to check this.

Figure A-1. How Do I Determine if My Well is a Low Pressure Well?



Static Pressure at the Wellhead

If you suspect that your well may be a low pressure well, you have the option of checking the wellhead static pressure (i.e., pressure with the well shut in and not flowing) following fracturing and prior to the onset of flowback. If the static pressure at the wellhead is less than the pressure at the sales meter of the flow line to which you would direct the recovered gas, the well qualifies as a low pressure well.

To use this option, measure the static pressure at the wellhead with the well shut in, after fracturing but before the onset of flowback. Measure the static pressure at the wellhead using standard industry methods.

When you have measured the static pressure at the wellhead, compare it to the flow line pressure at the sales meter. If the static pressure measured at the wellhead is less than the flow line pressure, the well qualifies as a low pressure well. You will need to keep a record to document this determination and submit that documentation in the initial annual report for the well. [§60.5420a(b)(2)(iii) and §60.5420a(c)(1)(vii)]

If the static pressure measured at the wellhead is not less than the flow line pressure at the sales meter, you may still be able to qualify the well as a low pressure well using the low pressure well equation included in the rule. This is possible because the dynamic pressure that you calculate for the well using the low pressure well equation should be lower than the static pressure you measured at the wellhead. The next section explains how to use the low pressure well equation.

Low Pressure Well Equation

You may also use the low pressure well equation to calculate the pressure of flowback fluid immediately before it enters the flow line, so that this value can be compared to the flow line pressure at the sales meter. If the calculated pressure is lower than the flow line pressure, your well qualifies as a low pressure well.

> *If you choose to calculate the pressure of flowback fluid immediately before it enters the flow line, you must use this calculation and the respective required inputs.*
> *No other calculation may be used to meet the rule requirement.*

This equation was developed using an energy balance that takes into account the main components of pressure drop for oil and gas wells – hydrostatic and frictional. It uses parameters for which values you can estimate, based on knowledge of the formation and reservoir and standard industry practice before starting a well completion operation.

These parameters include the following:

- Pressure of the reservoir containing oil, gas, and water at the well site, expressed in pounds per square inch absolute (psia), P_R;

- Bottom hole pressure, expressed in psia, PBH (also see Step 1);
- Bottom hole temperature, expressed in °F, TBH (also see Step 2);
- True vertical depth of the well, expressed in feet (ft.), L;
- Oil production rate, expressed in STBOD, Qo;
- Water production rate, expressed in STBOD, Qw;
- Gas production rate, expressed in standard cubic feet per day (scf/day), Qg; and
- Oil American Petroleum Institute (API) gravity at the well site, γo.

See the memo in the docket titled, "Technical Development of the Low Pressure Well Equation for Assessing REC Feasibility at Hydraulically Fractured Oil and Gas Wells" at **https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7617** for a detailed description of how to apply the low pressure well equation along with a sample calculation.