**Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After November 15, 2021**

Sec.

§§60.5433b-60.5439b [Reserved]

Table 1 to Subpart OOOOb of Part 60 – Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections with Quarterly OGI or EPA Method 21 Monitoring

Table 2 to Subpart OOOOb of Part 60 — Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring

Table 3 to Subpart OOOOb of Part 60 – Required Minimum Initial $SO_2$ Emission Reduction Efficiency ($Z_i$)

Table 4 to Subpart OOOOb of Part 60 – Required Minimum $SO_2$ Emission Reduction Efficiency ($Z_c$)

Table 5 to Subpart OOOOb of Part 60 – Applicability of General Provisions to Subpart OOOOb

**§60.5360b What is the purpose of this subpart?**

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after November 15, 2021. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide ($SO_2$) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after November 15, 2021.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.*

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to GHG emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

**§60.5365b Am I subject to this subpart?**

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (l) of this section for which you commence construction, modification, or reconstruction after November 15, 2021. Centrifugal compressor affected facilities listed in paragraph (b) of this section that use dry seals are subject to the applicable provisions of this subpart if construction, modification, or reconstruction are commenced after **[INSERT DATE OF PUBLICATION OF SUPPLEMENTAL PROPOSAL IN THE FEDERAL REGISTER]**.

(a) Each well affected facility, which is a single well.

(1) In addition to §60.14, a "modification" of an existing well occurs when:

(i) An existing well is hydraulically fractured, or

(ii) An existing well is hydraulically refractured.

(2) Except as provided in §60.5365b(e)(3)(ii)(C) and (i)(3)(iii), any action described by paragraph (a)(1)(i) through (ii), by itself, does not affect the modification status of process unit equipment, centrifugal or reciprocating compressors, pneumatic pumps, or pneumatic controllers.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart.

(d) Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records in §60.5420b(c)(6)(i)(A) or (B) are maintained, as applicable.

(1) For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of pneumatic controllers at a site is increased by one or more.

(2) For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of pneumatic controllers is replaced. That is, if an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii),

“commenced” means that an owner or operator has undertaken a continuous program of pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of pneumatic controller replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic controllers at the site. The “fixed capital cost of the new pneumatic controllers” includes the fixed capital cost of all pneumatic controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period following **[INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]**.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following **[INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]**. If an owner or operator determines reconstruction based on the percentage of pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator’s review.

(e) Each storage vessel affected facility, which is a tank battery that has the potential for emissions as specified in either paragraph (e)(1)(i) or (ii) of this section. A tank battery with the potential for emissions below both of the thresholds specified in paragraphs (e)(1)(i) and (ii) is not a storage vessel affected facility provided the owner/operator keeps records of the potential for emissions calculation for the life of the storage vessel or until such time the tank battery becomes a storage vessel affected facility because the potential for emissions meets or exceeds either threshold specified in either paragraph (e)(1)(i) or (ii) of this section.

(1)(i) Potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined in paragraph (e)(2) of this section.

(ii) Potential for methane emissions equal to or greater than 20 tpy as determined in paragraph (e)(2) of this section.

(2) The potential for VOC and methane emissions must be calculated as the cumulative emissions from all storage vessels within the tank battery as specified by the applicable requirements in paragraphs (e)(2)(i) through (iii) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.

(i) For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit must include the elements provided in paragraphs (e)(2)(i)(A) through (F) of this section.

(A) A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;

(B) An averaging time period for the production limit in (e)(2)(i)(A), if a production-based limit is used, that is equal to or less than 30 days;

(C) Established parametric limits for the production and/or operational limit(s) in (e)(1)(i)(A), and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.,* performance test) for the control device that establishes the parametric limits;

(D) Ongoing monitoring of the parametric limits in (e)(2)(i)(C) that demonstrates continuous compliance with the production and/or operational limit(s) in (e)(2)(i)(A);

(E) Recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (e)(2)(i)(A) through (D); and

(F) Periodic reporting that demonstrates continuous compliance.

(ii) For each tank battery located at a well site or centralized production facility, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

(A) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on the throughput to the tank battery established in a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority; or

(B) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.*, volumetric condensate rates from the tank battery based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the tank battery.

(3) For the purposes of §60.5395b, the following definitions of "reconstruction" and "modification" apply for determining when an existing tank battery becomes a storage vessel affected facility under this subpart.

(i) "Reconstruction" of a tank battery occurs when any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

(A) At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or

(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.

(ii) "Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through (D) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

(A) A storage vessel is added to an existing tank battery;

(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases;

(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).

(D) For tank batteries at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (*i.e.*, prior to an action in paragraphs (e)(3)(ii)(A), (B) or (D) of this section) determination of the potential for VOC or methane emissions.

(4) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(5) For storage vessels not subject to a legally and practicably enforceable limit in an operating permit or other requirement established under Federal, state, local, or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a vapor recovery unit designed and operated as specified in this section is not required to be included in the determination of potential for VOC emissions for purposes of determining affected facility status, provided you comply with the requirements of paragraphs (e)(5)(i) through (iv) of this section.

(i) You meet the cover requirements specified in §60.5411b(b).

(ii) You meet the closed vent system requirements specified in §60.5411b(a)(2) through (4) and (c).

(iii) You must maintain records that document compliance with paragraphs (e)(5)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(5)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility or portion of a storage vessel affected facility that is reconnected to the original source of liquids remains 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 a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

(7) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) Each process unit equipment affected facility, which is the group of all equipment within a process unit at an onshore natural gas processing plant is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered

by §§60.5400b, 60.5401b, 60.5402b, 60.5421b, and 60.5422b if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400b, 60.5401b, 60.5402b, 60.5421b, and 60.5422b.

(g) Each sweetening unit affected facility as defined by paragraphs (g)(1) and (2).

(1) Each sweetening unit that processes natural gas produced from either onshore or offshore wells is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide ($H_2S$) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423b(c) but are not required to comply with §§60.5405b through 60.5407b and §§60.5410b(i) and 60.5415b(i).

(4) 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 not subject to §§60.5405b through 60.5407b, 60.5410b(i), 60.5415b(i), and 60.5423b.

(h) Each pneumatic pump affected facility, which is the collection of natural gas-driven diaphragm and piston pneumatic pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Pneumatic pumps that are not driven by natural gas are not included in the pneumatic pump affected facility, provided the records in §60.5420b(c)(15)(i) are maintained.

(1) For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of  pneumatic pumps at a site is increased by one or more.

(2) For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the "number of pumps" criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all pneumatic pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period following **[INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]**.

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all pneumatic pumps which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period following **[INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]**. If an owner or operator determines reconstruction based on the percentage of pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

(3) A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.

(i) Each fugitive emissions components affected facility, which is the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station.

(1) For purposes of §60.5397b and §60.5398b, a “modification” to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(2) For purposes of §60.5397b and §60.5398b, a “modification” to centralized production facility occurs when:

(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;

(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or

(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.

(3) For purposes of §60.5397b, a “modification” to a compressor station occurs when:

(i) An additional compressor is installed at a compressor station; or

(ii) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §60.5397b.

(j) Each super-emitter affected facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.

**§60.5370b When must I comply with this subpart?**

(a) You must be in compliance with the standards of this subpart no later than **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** or upon initial startup, whichever is later, except as specified in paragraph (a)(1) of this section for reciprocating compressor affected facilities, paragraphs (a)(2) and (3) of this section for storage vessel affected facilities, and paragraph (a)(4) for process unit equipment affected facilities at onshore natural gas processing plants.

(1) You must comply with the requirements of §60.5385b(a) for your reciprocating compressor affected facility as specified in paragraphs (a)(1)(i) and (ii) or (a)(1)(iii) of this section, as applicable.

(i) You must comply with the requirements of §60.5385b(a)(1) on or before 12 months after **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** or on or before 12 months after initial startup, whichever is later; and

(ii) You must comply with the requirements of §60.5385b(a)(2) within 30 days after compliance with §60.5385b(a)(1).

(iii) You must comply with the requirements of §60.5385b(a)(3) for your reciprocating compressor upon initial startup.

(2) You must comply with the requirements of paragraphs §60.5395b(a)(1) for your storage vessel affected facility as specified in paragraphs (a)(2)(i) or (ii) of this section, as applicable.

(i) Within 30 days after startup of production, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a well site or centralized production facility.

(ii) Prior to startup of the compressor station or onshore natural gas processing plant, or within 30 days after reconstruction or modification of the storage vessel affected facility, for each storage vessel affected facility located at a compressor station or onshore natural gas processing plant.

(3) You must comply with the requirements of paragraph §60.5395b(a)(2) as specified in paragraph (a)(3)(i) or (ii) of this section, as applicable:

(i) For each storage vessel affected facility located at a well site or centralized production facility, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(i) of this section.

(ii) For storage vessel affected facilities located at a compressor station or onshore natural gas processing plant, you must achieve the required emissions reductions within 30 days after the determination in paragraph (a)(2)(ii) of this section.

(4) You must comply with the requirements of §60.5400b for all process unit equipment affected facilities at a natural gas processing plant, as soon as practicable but no later than 180 days after the initial startup of the process unit.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

**§60.5371b What GHG and VOC standards apply to super-emitter affected facilities?**

This section applies to super-emitter affected facilities. For purposes of this section, a super-emitter emissions event is defined as any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater. Paragraph (a) of this section describes the qualifications that a notifier of super-emitter emissions events must meet to require an action on the part of an owner or operator in accordance with paragraphs (c) and (d). Paragraph (b) of this section contains the information that must be included in any notification to you (*i.e.*, the owner or operator of the site with the detected super-emitter emissions event). Upon receiving such a notification, you must take the actions listed in paragraphs (c) and (d) of this section. If the notifier is not the Administrator, delegated authority, or an approved notifier as specified in paragraph (a) of this section, you are not required to take the actions listed in paragraphs (c) and (d) of this section.

(a) *Qualifications for notification.* If, in the Administrator's judgement, a third-party (*i.e.*, someone other than the owner or operator of the site with a detected super-emitter emissions event, the Administrator, or the delegated authority) demonstrates technical expertise in any of the remote detection technologies and/or methods specified in paragraphs (a)(1) through (3) of this section the third-party would use, the Administrator will approve that third-party as a qualified notifier that is eligible to submit a notification of a super-emitter emissions event to an owner or operator as specified in paragraph (b) of this section.

(1) Satellite detection of methane emissions.

(2) Remote-sensing equipment on aircraft.

(3) Mobile monitoring platforms.

(4) Any owner or operator that has received more than three notices of a super-emitter emissions event at the same well site, centralized production facility, or compressor station from the same third party may petition the Administrator to remove that third party from the approved list. Such petitions may not be used to dispute the accuracy of technologies using methodology that were approved through the alternative test method process described in §60.5398b(d). If, in the Administrator's discretion, the notifications contain meaningful, demonstrable errors, including that the third party did not use the appropriate methane detection technology, or that the emissions event did not exceed the threshold, that third party may be removed by the Administrator from the approved super-emitter notification list. Where such demonstrable error is identified, the owner or operator must submit a report indicating the error as specified in paragraph (e)(1) of this section. The failure of the operator to find the source of the super-emitter event upon subsequent inspection shall not be proof, by itself, of demonstrable error.

(b) *Notification of super-emitter emissions events.* The notification provided to the owner or operator must contain the information specified in paragraphs (b)(1) through (6) of this section by the date specified in paragraph (b)(7) of this section.

(1) Location of emissions in latitude and longitude coordinates in decimal degrees to an accuracy and precision of four (4) decimals of a degree using the North American Datum of 1983.

(2) Description of detection technology and sampling protocols used to identify the emission event, including documentation that the detection technology and sampling protocols can detect methane emissions of 100 kg/hr or greater in the conditions present during the survey.

(3) Documentation depicting the detected emission event and the site from which the emission event was detected.

(4) Quantified emission rate, in kg/hr, associated uncertainty bounds, and any meta data (including the conditions present during the survey) required in the sampling protocols needed to confirm these results.

(5) Date(s) of detection of super-emitter emissions event and date(s) of confirmation of emission rate.

(6) Certification, signed and dated by the person submitting the data collected. The certification must state: "I certify that I meet the qualifications of a notifier under 40 CFR 60.5371b(a) and that the emission detection information included in this notification was collected and interpreted as described in this notification. Based on my professional knowledge and experience, and inquiry of personnel involved in the collection and analysis of the data, the certification submitted herein is true, accurate, and complete."

(7) The notifier must submit the notification as soon as practicable to the owner or operator of the site with the super-emitter emissions event. The notifier must also submit a copy of the notification to the Administrator and to any delegated authority on the same day that

notification is made to the owner or operator. The Administrator shall make such notifications publicly available at [webpage].

(c) *Addressing super-emitter emissions events.* Within 5 days of receiving the notification of a super-emitter emissions event, you must initiate a root cause analysis to determine the cause of such emissions and to determine appropriate corrective action, such as those described in paragraphs (c)(1) through (8) of this section. The root cause analysis and initial corrective action must be completed no later than 10 calendar days after receiving notification of a super-emitter emissions event. Root cause analysis and initial corrective action may include but is not limited to the items in paragraph (c)(1) through (9) of this section. Root cause analysis must include the information in paragraph (c)(10) of this section.

(1) Leak inspection using optical gas imaging and repairing any leaks found.

(2) Leak inspection using an advanced methane detection technology and repairing any leaks found.

(3) Leak inspection using Method 21 of appendix A-7 of this part and repairing any leaks found.

(4) Visual inspection of a controlled tank battery to determine if an open thief hatch or pressure relief device on a controlled tank battery is the cause of the emissions and implementing repairs to eliminate the emissions and achieve the no identifiable emissions standard, in addition to conducting a new engineering certification to ensure the controlled tank battery is designed and operated to achieve the no identifiable emissions standard.

(5) Visual inspection of a separator dump valve to determine if the valve is stuck in an open position, thus allowing gas carry-through to the controlled tank battery and repairing any dump valve not operating as designed.

(6) Visual inspection of a combustion control device to determine if the pilot is lit and reigniting the pilot if found unlit; evaluation of heat content in the combustion zone and raising the heat content by supplementing the vented gas with natural gas (or propane) or adjusting air (or steam) assist rate, if used; and analysis of compliance with operating parameter limits established in §60.5417b.

(7) Visual or instrument inspection of natural gas-driven pneumatic controllers and pumps to determine if they are venting to the atmosphere continuously and repairing any controllers that are found venting to the atmosphere during idle periods.

(8) Documentation that emissions were the result of allowed venting of emissions as part of normal operations, including routine maintenance (if applicable).

(9) Documentation that any operational or maintenance practices identified as part of the root cause for the super-emitter emissions event have been revised (if needed) to prevent or reduce the likelihood of future super-emitter events.

(10) Identification of the source or possible source of emissions identified in the report and the applicable standard to which the emissions source is subject (if applicable).

(d) *Corrective action plans for additional analysis.* If, upon completion of the root cause analysis and initial corrective actions such as those described in paragraph (c) of this section, you are notified of a super-emitter emissions event from the same emission source which was determined under paragraph (c) not to be an allowed venting of emissions as part of normal operations, including routine maintenance, or if the initial corrective actions will require more than 10 days to complete, you must develop a corrective action plan that describes the initial corrective action(s) completed to date, additional measures that you propose to employ to reduce or eliminate the super-emitter emissions event, and a schedule for completion of these additional measures. You must submit the corrective action plan to the Administrator according to the schedule in paragraphs (d)(1) and (2) of this section.

(1) If you are submitting a corrective action plan because you were notified of a super-emitter event from an emissions source which you had previously completed actions in paragraph (c) of this section, you must submit the corrective action plan within 30 days after receipt of the notification.

(2) If you are submitting the corrective action plan because you were unable to complete the actions in paragraph (c) in 10 days, you must submit the corrective action plan within 30 days of the notification in paragraph (b) of this section.

(e) *Reporting requirements.* You must submit a report to the Administrator in accordance with (e)(1) of this section after receipt of a notification in paragraph (b) of this section. You must submit the information in paragraph (e)(2) of this section if you are required to develop a corrective action plan under paragraph (d) of this section. You must certify the information included in the report as specified in paragraph (e)(3) of this section.

(1) An owner or operator of a super-emitter affected facility shall notify the Administrator within 15 days of completing the corrective actions required by §60.5371b(c). The notification shall include the requirements in paragraphs (e)(1)(i) through (iv) of this section. If the owner or operator has identified a demonstrable error in the notification, the report may instead include a statement of the demonstrable error as specified in §60.5371b(a)(4).

(i) The date you received the notification in paragraph (c) of this section from the delegated authority or approved notifier.

(ii) The information in paragraphs (e)(1)(ii)(A) through (E) contained in the super-emitter event notification you received from the Administrator, a delegated authority, or approved notifier.

(A) Location of emissions in latitude and longitude coordinates in decimal degrees to an accuracy and precision of four (4) decimals of a degree using the North American Datum of 1983.

(B) Description of detection technology and sampling protocols used to identify the emission event, including documentation that the detection technology and sampling protocols can detect methane emissions of 100 kg/hr or greater in the conditions present during the survey.

(C) Documentation depicting the detected emission event and the site from which the emission event was detected.

(D) Quantified emission rate, in kg/hr, associated uncertainty bounds, and any meta data (including the conditions present during the survey) required in the sampling protocols needed to confirm these results.

(E) Date(s) of detection of super-emitter emissions event and date(s) of confirmation of emission rate.

(iii) The date(s) you conducted the inspections required by paragraph (c), the date you identified the source(s) of the emissions, a description of the emissions source, the applicable standard to which the emissions source is subject (if applicable), and a statement regarding the compliance status of the emissions source to that standard.

(iv) A description of all corrective actions taken to eliminate the super-emitter emissions events, including actions taken to bring the affected facility back into compliance if the source of emissions was the result of noncompliance with the applicable standards in this subpart. This description must include verification and date of successful repair that demonstrates the super-emitter emissions event is no longer present.

(2) You must submit a corrective action plan to the if you are subject to paragraph (d) of this section according to the schedule in paragraph (e)(2)(i) and (ii).

(i) If you are submitting a corrective action plan because you were notified of a super-emitter event from an emissions source which you had previously completed actions in paragraph (c) of this section, you must submit the corrective action plan within 30 days after receipt of the notification.

(ii) If you are submitting the corrective action plan because you were unable to complete the actions in paragraph (c) in 10 days, you must submit the corrective action plan within 30 days of the notification you received in accordance with paragraph (b) of this section.

(3) The following certification, signed and dated by the owner or operator, shall state: “I certify that the information provided in this report regarding notification, root cause, and corrective action of the specified super-emitter emissions event was prepared under my direction or supervision. I further certify that the root cause analysis and corrective actions were conducted, and this report was prepared pursuant to the requirements of §60.5371b(c) and (d). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

(4) Upon receipt of the report required by paragraph (e) of this section, the Administrator shall make such report publicly available at [website].

(5) You must submit the information in §60.5420b(b)(14) in your annual report.

**§60.5375b What GHG and VOC standards apply to well completions at well affected facilities?**

(a) You must comply with the requirements of paragraphs (a)(1) through (3) of this section for each well completion operation with hydraulic fracturing and refracturing at a well affected facility, except as provided in paragraphs (f), (g) and (h) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. The separator may be a production separator, but the production separator also must be designed to accommodate flowback. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements of paragraph (a)(2) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have the separator onsite or otherwise available for use at a centralized production facility or well pad that services the well completion affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with §60.5375b(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in §60.5420b(b)(2) and maintain the records in §60.5420b(c)(1)(iii).

(2) If it is technically infeasible to route the recovered gas as required in §60.5375b(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(3) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in §60.5420b(c)(1)(iii).

(c) You must demonstrate initial compliance with the well completion operation standards that apply to well affected facilities as required by §60.5410b(a).

(d) You must demonstrate continuous compliance with the well completion operation standards that apply to well affected facilities as required by §60.5415b(a).

(e) You must perform the required notification, reporting and recordkeeping as required by §60.5420b(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with paragraph (f)(3)(i) of this section. You must also comply with paragraph (b) of this section. As an alternative, if you are able to operate a separator, you may comply with paragraph (b) and (f)(3)(ii) of this section. Compliance with paragraphs (f)(3)(i) or (ii) of this section is not required if you meet the requirements of paragraph (g) of this section.

(i) 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. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. You must have the separator onsite or otherwise available for use at the wildcat well, delineation well, or low pressure well. The separator must be available and ready for use to comply with paragraph (f)(3)(ii) of this section during the entirety of the flowback period. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You must submit the notification as specified in §60.5420b(a)(2), submit annual reports as specified in §60.5420b(b)(1) and (2) and maintain records specified in §60.5420b(c)(1)(i) through (iii) and (vii) for each wildcat well, each delineation well, and each low pressure well.

(g) For each well completion affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in §60.5420b(c)(1)(vi).

(2) You must submit reports specified in §60.5420b(b)(1) and (2).

(h) A well modified in accordance with § 60.5365b(a)(1)(ii) (*i.e.*, an existing well is hydraulically refractured) is exempt from the well completion operation standards in paragraphs (b) through (d) of this section, when the requirements of paragraphs (a)(1) through (3) of this section are met.

**§60.5376b What GHG and VOC standards apply to gas well liquids unloading operations at well affected facilities?**

(a) *General requirements.* You must comply with the requirements of this section for each gas well liquids unloading operation at your well affected facility. You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during gas well liquids unloading operations.

(b) *Zero emissions standard.* You must perform each gas well liquids unloading operation with zero methane and VOC emissions, except as provided in paragraph (c) of this section. You must also comply with the requirements in paragraphs (b)(1) and (2), and (e) through (g) of this section.

(1) You must comply with the recordkeeping requirements specified in §60.5420b(c)(2)(i).

(2) You must comply with the annual reporting requirements specified in §60.5420b(b)(1) and (b)(3)(i).

(c) *Exception to zero emissions standard.* If it is not feasible to perform a gas well liquids unloading operation with zero methane and VOC emissions due to technical or safety reasons, you must comply with the requirements in paragraphs (c)(1) through (4) and (d) through (g) of this section.

(1) Provide written justification for the need for each exception, including supporting documentation as specified in §60.5420b(b)(3)(ii)(B).

(2) Employ best management practices to minimize venting of methane and VOC emissions as specified in paragraph (d) of this section for each gas well liquids unloading operation.

(3) Comply with the recordkeeping requirements specified in §60.5420b(c)(2)(ii).

(4) Submit the information specified in §60.5420b(b)(1) and (b)(3)(ii) in the annual report.

(d) *Best management practice requirements*. For each gas well liquids unloading operation complying with the exception in paragraph (c) of this section, you must develop, maintain, and follow a best management practice plan to minimize venting of methane and VOC emissions to the maximum extent possible from each gas well liquids unloading operation. This best management practice plan must meet the minimum criteria specified in paragraphs (d)(1) through (4) of this section.

(1) Include steps that create a differential pressure to minimize the need to vent a well to unload liquids,

(2) Include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,

(3) Unload liquids through the separator where feasible, and

(4) Close all wellhead vents to the atmosphere and return the well to production as soon as practicable.

(e) You must demonstrate initial compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by §60.5410b(b).

(f) You must demonstrate continuous compliance with the standards that apply to well liquids unloading operations at your well affected facilities as required by §60.5415b(b).

(g) You must perform the required notification, recordkeeping and reporting requirements as specified in §60.5420b(b)(3) and (c)(2).

**§60.5377b What GHG and VOC standards apply to oil wells with associated gas at well affected facilities?**

(a) You must comply with either paragraph (a)(1), (2), (3), or (4) of this section for each oil well with associated gas at a well affected facility, except as provided in paragraph (b) of this section. You must also comply with paragraphs (c), (d), and (e) of this section.

(1) Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line.

(2) Recover the associated gas from the separator and use the recovered gas as an onsite fuel source.

(3) Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.

(4) Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well for enhanced oil recovery.

(b) If you demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section due to technical or safety reasons in accordance with paragraphs (b)(1) through (3) of this section, you must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of §60.5411b(a) and (c) and the control device must meet the conditions specified in §60.5412b(a), (b) and (c).

(1) In order to demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section, you must provide a detailed analysis documenting and certifying the technical or safety reasons for this infeasibility. The demonstration must address the technical or safety infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section. With regard to compliance with paragraph (a)(3) of this section, another useful purpose that a purchased fuel or raw material would serve includes, but is not limited to, methane pyrolysis, compressing the

gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas. Documentation of these demonstrations must be maintained in accordance with §60.5420b(c)(3)(ii).

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer of other qualified individual shall state: "I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of §60.5377b(b)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(c) You must demonstrate initial compliance with the standards that apply to oil wells with associated gas at well affected facilities as required by §60.5410b(c).

(d) You must demonstrate continuous compliance with the standards that apply to oil wells with associated gas at well affected facilities as required by §60.5415b(c).

(e) You must perform the required recordkeeping and reporting as required by §60.5420b(b)(4), and (b)(11) and (12), as applicable, and (c)(3) and (8) and (c)(10) through (13), as applicable.

**§60.5380b What GHG and VOC standards apply to centrifugal compressor affected facilities?**

Each centrifugal compressor affected facility must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section.

(a) Each centrifugal compressor affected facility that uses wet seals must comply with the GHG and VOC standards in paragraphs (a)(1) and (2), or paragraph (a)(3), of this section. Each centrifugal compressor affected facility that uses dry seals, and each self-contained wet seal compressor, must comply with the GHG and VOC standards in paragraph (a)(4) and (5) of this section.

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

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412b(a), (b) and (c).

(3) As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process or utilize a self-contained wet seal centrifugal compressor.

(i) If you route the emissions to a process, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411b(a) and (c).

(ii) If you utilize a self-contained wet seal centrifugal compressor, you must comply with the GHG and VOC standards in paragraph (a)(4) and (5) of this section.

(4) Each centrifugal compressor affected facility that uses dry seals, or that is a self-contained wet seal compressor, must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, as specified in paragraphs (a)(4)(i) through (iii), and with paragraph (a)(5) of this section.

(i) The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm). You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.

(ii) You must conduct your first volumetric flow rate measurement from your centrifugal compressor dry seal vent or self-contained wet seal compressor on or before 8,760 hours of operation after **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** or on or before 8,760 hours of operation after startup, whichever is later.

(iii) You must conduct subsequent volumetric flow rate measurements from your centrifugal compressor dry seal vent or self-contained wet seal centrifugal compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 3 scfm volumetric flow rate.

(5) You must determine the volumetric flow rate from your centrifugal compressor dry seal vent or self-contained wet seal centrifugal compressor as specified in paragraph (a)(5)(i) or (ii) of this section.

(i) For centrifugal compressor dry seal vents or self-contained wet seal centrifugal compressor in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry seal vent or self-contained wet seal centrifugal compressor using one of the methods specified in paragraphs (a)(5)(i)(A) through (C) of this section. If there is more than one dry seal vent or self-contained wet seal centrifugal compressor, determine the aggregate dry seal vent or self-contained wet seal centrifugal compressor volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for each centrifugal compressor dry seal vent or self-contained wet seal centrifugal compressor.

(A) You may choose to use any of the methods set forth in §60.5386b(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in §60.5386b(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in §60.5386b(a), then you must use one of the methods specified in paragraph (a)(5)(i)(B) or (C) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5386b(a), then you may assume that the volumetric emissions are zero.

(B) Use a temporary or permanent flow meter according to methods set forth in §60.5386b(b).

(C) Use a high-volume sampler according to the method set forth in §60.5386b(c).

(ii) For conducting measurements on manifolded groups of dry seal centrifugal compressors or self-contained wet seal centrifugal compressors, you must determine the volumetric flow rate from the compressor dry seal or self-contained wet seal centrifugal compressor as specified in paragraph (a)(5)(ii)(A) or (B) of this section.

(A) Measure at a single point in the manifold downstream of all dry seal or self-contained wet seal centrifugal compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(B) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(5)(i)(A) through (C) of this section.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410b(d).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415b(d).

(d) You must perform the reporting as required by §60.5420b(b)(1) and (5) and (b)(11) through (13), as applicable, and the recordkeeping as required by §60.5420b(c)(4) and (8) through (13), as applicable.

**§60.5385b What GHG and VOC standards apply to reciprocating compressor affected facilities?**

Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, in paragraphs (a) through (c) of this section, or the GHG and VOC standards in paragraph (d) of this section. You must also comply with the requirements in paragraphs (e) through (g) of this section.

(a) The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm). You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

(1) You must conduct your first volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** or on or before 8,760 hours of operation after startup, whichever is later.

(2) You must conduct subsequent volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 2 scfm volumetric flow rate.

(b) You must determine the volumetric flow rate from your reciprocating compressor rod packing as specified in paragraph (b)(1) or (2) of this section.

(1) For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate using one of the methods specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in §60.5386b(c).

(ii) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in §60.5386b(b).

(iii) Any of the methods set forth in §60.5386b(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in §60.5386b(a). If emissions are detected using the methods set forth in §60.5386b(a), then you must use one of the methods specified in paragraph (b)(1)(i) and (b)(1)(ii) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5386b(a), then you may assume that the volumetric emissions are zero.

(2) For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, you must determine the volumetric flow rate using the methods specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) You must use the methods described in §60.5386b(a) to conduct leak detection of emissions from the packing case into an open distance piece, or, for compressors with a closed distance piece, you must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(ii) You must measure emissions found in paragraph (b)(2)(i) of this section using a meter or high-volume sampler according to methods set forth in §60.5386b(b) or (c).

(c) For conducting measurements on manifolded groups of reciprocating compressor affected facilities, you must determine the volumetric flow rate from reciprocating compressor rod packing as specified in paragraph (c)(1) and (2) of this section.

(1) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(2) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (c)(2)(i) through (iv) of this section.

(i) A temporary or permanent flow meter according to the methods set forth in §60.5386b(b).

(ii) A high-volume sampler according to methods set forth §60.5386b(c).

(iii) An alternative method, as set forth in §60.5386b(d).

(iv) Any of the methods set forth in §60.5386b(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in §60.5386b(a). If emissions are detected using the methods set forth in §60.5386b(a), then you must use one of the methods specified in paragraph (c)(2)(i) through (iii) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5386b(a), then you may assume that the volumetric emissions are zero.

(d) Collect the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process through a closed vent system that meets the requirements of §60.5411b(a) and (c).

(e) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410b(e).

(f) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415b(g).

(g) You must perform the reporting requirements as specified in §60.5420b(b)(1) and (b)(6) and (11), as applicable, and the recordkeeping requirements as specified in §60.5420b(c)(5) and (8), (10) and (12), as applicable.

**§60.5386b What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor affected facilities?**

(a) You must use one of the methods described in paragraph (a)(1) and (2) of this section to screen for emissions or leaks from the reciprocating compressor rod packing when complying with §60.5385b(b)(1)(iii) and from the compressor dry seal vent when complying with §60.5380b(a)(5)(i)(A).

(1) *Optical gas imaging instrument*. Use an optical gas imaging instrument for equipment leak detection as specified in either paragraph (a)(1)(i) or (ii) of this section. For the purposes of paragraphs (a)(1)(i) and (ii) of this section, any visible emissions observed by the optical gas imaging instrument from reciprocating rod packing or compressor dry seal vent is a leak.

(i) *Optical gas imaging instrument as specified in appendix K of this part*. For reciprocating compressor and dry seal centrifugal compressor affected facilities located at onshore natural gas processing plants, use an optical gas imaging instrument to screen for emissions from reciprocating rod packing or centrifugal compressor dry seal vent in accordance with the protocol specified in appendix K of this part.

(ii) *Optical gas imaging instrument as specified in §60.5397b of this subpart*. For reciprocating compressor and centrifugal dry seal compressor affected facilities located at centralized production facilities, compressor stations, or other location that is not an onshore natural gas processing plant, use an optical gas imaging instrument to screen for emissions from reciprocating rod packing or compressor dry seals in accordance with the elements of §60.5397b(c)(7).

(2) *Method 21*. Use Method 21 in appendix A-7 of this part according to §60.5403b(b)(1) and (2). For the purposes of this section, an instrument reading of 500 ppmv above background or greater is a leak.

(b) You must determine natural gas volumetric flow rate using a rate meter which meets the requirement in Method 2D in Appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D.

(c) You must use a high-volume sampler to measure emissions of the reciprocating compressor rod packing or centrifugal compressor dry seal vent in accordance with paragraphs (c)(1) through (7) of this section.

(1) You must use a high-volume sampler designed to capture the entirety of the emissions from the applicable vent and measure the entire range of methane concentrations being emitted as well as the total volumetric flow at standard conditions. You must develop a standard operating procedure for this device and document these procedures in the appropriate monitoring plan. In order to get reliable results, persons using this device should be knowledgeable in its operation and the requirements in this section.

(2) This procedure may involve hazardous materials, operations, and equipment. This procedure may not address all of the safety problems associated with its use. It is the

responsibility of the user of this procedure to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this procedure.

(3) The high-volume sampler must include a methane gas sensor(s) which meets the requirements in paragraphs (c)(3)(i) through (iii) of this section.

(i) The methane sensor(s) must be selective to methane with minimal interference, less than 2.5 percent for the sum of responses to other compounds in the gas matrix. You must document the minimal interference though empirical testing or through data provided by the manufacturer of the sensor.

(ii) The methane sensor(s) must have a measurement range over the entire expected range of concentrations.

(iii) The methane sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(4) The high-volume sampler must be designed such that it is capable of sampling sufficient volume in order to capture all emissions from the applicable vent. Your high-volume sampler must include a flow measurement sensor(s) which meets the requirements of paragraphs (c)(4)(i) and (ii) of this section.

(i) The flow measurement sensor must have a measurement range over the entire expected range of flow rates sampled. If needed multiple sensors may be used to capture the entire range of expected flow rates.

(ii) The flow measurement sensor(s) must be capable of taking a measurement once every second, and the data system must be capable of recording these results for each sensor at all times during operation of the sampler.

(5) You must calibrate your methane sensor(s) according to the procedures in paragraphs (c)(5)(i)(A) and (B) of this section, and flow measurement sensors must be calibrated according to the procedures in paragraph (c)(5)(ii) of this section.

(i) Methane Sensor Calibration.

(A) Initially and on a semi-annual basis, determine the linearity at four points through the measurement range for each methane sensor using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less than 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor, and do not use the sampler until these criteria can be met.

(B) Prior to and at the end of each testing day, challenge each sensor at two points, a low point, and a mid-point, using methane gaseous calibration cylinder standards. At each point, the difference between the cylinder value and the sensor reading must be less 5 percent of the respective calibration gas value. If the sensor does not meet this requirement, perform corrective action on the sensor and do not use the sampler again until these criteria can be met. If the post-test calibration check fails at either point, invalidate the data from all tests performed subsequent to the last passing calibration check.

(ii) Flow measurement sensors must meet the requirements in Method 2D in Appendix A-1 of this part. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D. If your flow sensor relies on ancillary temperature and pressure measurements to correct the flow rate to standard conditions, the temperature and pressure sensors must also be calibrated on an annual basis. Standard conditions are defined as 20°C (68°F) and 760 mm Hg (29.92” Hg).

(6) You must conduct sampling of the reciprocating compressor rod packing or centrifugal compressor dry seal vent in accordance with the procedures in paragraphs (c)(6)(i) through (v) of this section.

(i) The instrument must be operated consistent with manufacturer recommendations; users are encouraged to develop a standard operating procedure to document the exact procedures used for sampling.

(ii) Identify the rod packing or centrifugal compressor dry seal vent to be measured and record the signal to noise ratio (S/N) of the engine. Collect a background methane sample in parts per million by volume (ppmv) for a minimum of one minute and record the result along with the date and time.

(iii) Approach the vent with the sample hose and adjust the sampler so that you are measuring at the full flow rate. Then, adjust the flow rate to ensure the measured methane concentration is within the calibrated range of the methane sensor and minimum methane concentration is at least 2 ppmv higher than the background concentration. Sample for a period of at least one minute and record the average flowrate in standard cubic feet per minute and the methane sample concentration in ppmv, along with the date and time. Standard conditions are defined as 20°C (68°F) and 760 mm Hg (29.92" Hg).

(iv) Calculate the leak rate according to the following equation:

$$Q = V\left(\frac{CH4_S - CH4_B}{1000000}\right)$$

Where:

$CH4_B$= background methane concentration, ppmv

$CH4_S$= methane sample concentration, ppmv

V = Average flow rate of the sampler, scfm

Q = Methane emission rate, scfm

(v) You must collect at least three separate one-minute measurements and determine the average leak rate. The relative percent difference of these three separate samples should be less than 10 percent.

(7) If the measured natural gas flow determined as specified in paragraph (c)(6) of this section exceeds 70.0 percent of the manufacturer's reported maximum sampling flow rate you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use another method meeting the requirements in paragraph (d) of this section to determine the leak or flow rate.

(d) As an alternative to a high-volume sampler, you may use any other method that has been validated in accordance with the procedures specified in Method 301 in appendix A in 40 CFR part 63, subject to Administrator approval, as specified in §60.8(b).

**§60.5390b What GHG and VOC standards apply to pneumatic controller affected facilities?**

Each pneumatic controller affected facility must comply with the GHG and VOC standards in this section.

(a) You must design and operate each pneumatic controller affected facility with zero methane and VOC emissions to the atmosphere, except as provided in paragraph (b) of this section.

(1) If you comply by routing the emissions to a process, emissions must be routed to a process through a closed vent system that meets the requirements of §60.5411b(a) and (c).

(2) If you comply by using a self-contained natural gas-driven pneumatic controller, you must design and operate each self-contained natural gas pneumatic controller with no identifiable emissions, as demonstrated by §60.5416b(b).

(b) For each pneumatic controller affected facility located at a site in Alaska that does not have access to electrical power, you may comply with either paragraphs (b)(1) and (2) of this section or with paragraph (b)(3) of this section, as an alternative to complying with paragraph (a) of this section.

(1) With the exception of continuous controllers that meet the condition in paragraph (b)(1)(i) of this section and that comply with paragraph (b)(1)(ii) of this section, each continuous bleed pneumatic controller in the pneumatic controller affected facility must have a bleed rate less than or equal to 6 standard cubic feet per hour (scfh). You must maintain records in accordance with §60.5420b(c)(6)(iii) to demonstrate that the controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(i) A continuous bleed pneumatic controller with a bleed rate higher than 6 scfh can be used if it meets the requirements of paragraph (b)(1)(ii) of this section.

(ii) You must demonstrate that a controller with a bleed rate higher than 6 scfh is required. The demonstration must be based on the specific functional need, including but not limited to response time, safety, or positive actuation. You must keep records as specified in §60.5420b(c)(6)(iii) and submit the information in the initial annual report as specified in §60.5420b(b)(7)(iii)(A).

(2) Each intermittent vent pneumatic controller in the pneumatic controller affected facility must comply with the requirements in paragraphs (b)(2)(i) and (ii) of this section.

(i) Each intermittent vent controller must not emit to the atmosphere during idle periods.

(ii) You must monitor each intermittent vent pneumatic controller to ensure that it is not emitting to the atmosphere during idle periods, as specified in paragraphs (b)(2)(ii)(A) through (C) of this section.

(A) Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in §60.5397b(g).

(B) You must include the monitoring of each intermittent vent pneumatic controller in the monitoring plan required in §60.5397b(b).

(C) When monitoring identifies emissions to the atmosphere from an intermittent vent controller during idle periods, you must meet the requirements in paragraphs (b)(2)(ii)(C)(*1*) and (*2*) of this section.

(*1*) You must record the deviation of the standard in accordance with the requirements in §60.5420b(c)(6)(iv) and report it in your annual report in accordance with §60.5420b(b)(7)(iii)(B)

(*2*) You must take corrective action by repairing or replacing the intermittent vent pneumatic controller within 5 calendar days of the date the emissions to the atmosphere were detected. You must record the corrective action in accordance with §60.5420b(c)(6)(iv). After the repair or replacement of an intermittent vent pneumatic controller, you must re-survey the intermittent vent pneumatic controller within five days to verify that it is not venting emissions during idle periods.

(3) You must reduce methane and VOC emissions from all controllers in the pneumatic controller affected facility by 95.0 percent. You must route emissions to a control device through

a closed vent system that meets the requirements of §60.5411b(a) and (c), and the control device must meet the conditions specified in §60.5412b(a), (b) and (c).

(c) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410b(f).

(d) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415b(h).

(e) You must perform the reporting as required by §§60.5420b(b)(7) and (b)(11) through (13), as applicable and the recordkeeping as required by §§60.5420b(c)(6), and (c)(8) and (c)(10) through (13), as applicable.

**§60.5393b What GHG and VOC standards apply to pneumatic pump affected facilities?**

For each pneumatic pump affected facility you must comply with either paragraph (a) or (b) of this section.

(a) Except as provided in paragraph (b) of this section, pneumatic pumps must not be powered by natural gas.

(b) For each pneumatic pump affected facility located at a site that does not have access to electrical power, you may comply with paragraph (d) of this section if you demonstrate that the use of a pneumatic pump not powered by natural gas is infeasible in accordance with the requirements in paragraph (c) of this section.

(c) You must demonstrate that it is technically infeasible to utilize a solar powered pneumatic pump for each pneumatic pump that is part of an affected facility in accordance with paragraph (c)(1) of this section, and that it technically infeasible to utilize a generator to power a compressed air system for the pneumatic pump affected facility in accordance with paragraph (c)(2) of this section. Documentation of these demonstrations must be maintained in accordance with §60.5420b(c)(15)(iv).

(1) You must demonstrate that using a solar-powered electric pneumatic pump is not technically feasible. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of solar-powered pneumatic pumps. Alternatively, this demonstration can be certified by a solar-powered pneumatic pump manufacturer that has successfully installed solar-powered pneumatic pumps at other oil and natural gas sites. The following certification, signed and dated by the qualified professional engineer, in-house engineer, or solar pneumatic pump manufacturer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of §60.5393b(c)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(2) You must demonstrate that it is not technically feasible to install a compressed air system powered by either a natural gas-driven generator or a solar-powered generator for the pneumatic pump affected facility. This demonstration must include, but not be limited to, the ability to operate a generator, including access to natural gas; access to solar power; or the inability of a compressed air system to power the pneumatic pump. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of natural gas-driven or solar-powered generators to power pneumatic pumps. The following certification, signed and dated by the qualified professional engineer or in-house engineer shall state: "I certify that the assessment of technical infeasibility was prepared

under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393b(c)(2). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(d) You must collect vapors from all pneumatic pumps in the pneumatic pump affected facility and route all of the emissions to a process through a closed vent system that meets the requirements of §60.5411b(a) and (c). If you demonstrate, in accordance with paragraph (e) of this section, that it is technically infeasible to route the emissions to a process through a closed vent system, you must comply with paragraph (f) or (g) of this section. If the pneumatic pump affected facility is routed to a process and the process is subsequently removed from the location or is no longer available such that there is no ability to route to a process at the location, you are no longer required to be in compliance with the requirements of paragraph (d) of this section, and instead must comply with paragraph (f) of this section and report the change in the next annual report in accordance with §60.5420b(b)(10)(viii) and maintain the records in §60.5420b(c)(15)(iii).

(e) A demonstration that it is not technically feasible to route all of the emissions from all natural gas-driven pumps in the affected facility to a process. This demonstration must include, but not be limited to, safety considerations, distance from a process, pressure losses and differentials which impact the ability of the process to handle all of the pneumatic pump affected facility emissions routed to it, or other technical reasons the process cannot handle all of the pneumatic pump affected facility emissions routed to it. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump affected facility and the process to which emissions will be routed. The technical infeasibility may not include the infeasibility of the design and operation of closed vent systems to collect emissions from all of the pneumatic pumps in the affected facility. The following certification, signed and dated by the qualified professional engineer or in-house engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393b(e). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." Documentation of this demonstration must be maintained in accordance with §60.5420b(c)(15)(iv).

(f) You must reduce methane and VOC emissions from all natural gas-driven pneumatic pumps in the pneumatic pump affected facility by 95.0 percent. You must route all emissions to a control device through a closed vent system that meets the requirements of §60.5411b(a) and (c), and the control device must meet the conditions specified in §60.5412b(a), (b) and (c). As an alternative, you can comply with paragraph (g) of this section if you have less than four natural gas-driven pumps in the pneumatic pump affected facility.

(g) If you have less than four natural gas-driven pumps in the pneumatic pump affected facility, you are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (f) of this section. If you do not have a control device installed on site by the compliance date, then you must comply instead with the provisions of paragraphs (g)(1) and (2) of this section. For the purposes of this section, boilers and process heaters are not considered control devices. If you have a control device on site that is unable to achieve a 95.0 percent reduction you must comply with paragraph (g)(2) of this section. If an owner or operator determines, through an engineering assessment, that routing a pneumatic pump to an existing control device is technically infeasible, you must comply with the requirements in paragraph (g)(3) of this section.

(1) Submit a certification in accordance with §60.5420b(b)(10)(vi) in your next annual report, certifying that there is no available control device on site and maintain the records in §60.5420b(c)(15)(vi).

(i) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (g)(1) of this section and must submit the information in §60.5420b(b)(10)(ii) or (iii), as applicable, in your next annual report and maintain the records in §60.5420b(c)(15)(ii) and (v), as applicable.

(ii) You must be in compliance with the requirements of paragraph (f) of this section within 30 days of startup of the control device, except as specified in paragraph (g)(4) of this section, or you shall be in compliance with paragraph (d) of this section within 30 days of the ability to route to a process.

(2) If the control device available on site is unable to achieve a 95.0 percent reduction, you must still route the pneumatic pump affected facility emissions to that control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the certification specified in §60.5420b(b)(10)(vii) in your next annual report and maintain the records in §60.5420b(c)(15)(vii).

(3) If an owner or operator determines, through an engineering assessment, that routing the pneumatic pump affected facility emissions to a control device is technically infeasible, the requirements specified in paragraphs (g)(3)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (g)(3)(iii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump affected facility and the control device in accordance with paragraph (g)(3)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393b(g)(3)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(iii) The assessment of technical infeasibility to route emissions from the pneumatic pump to an existing control device shall include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, and the ability of the control device to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (g)(3)(ii) of this section.

(iv) The owner or operator shall maintain the records specified in §60.5420b(c)(15)(viii).

(4) If the pneumatic pump is routed to a control device and the control device is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are no longer required to be in compliance with the requirements of

paragraph (f) of this section, and instead must comply with paragraph (g)(1) of this section and report the change in the next annual report in accordance with §60.5420b(b)(10)(viii).

(h) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410b(g).

(i) You must demonstrate continuous compliance with the standards that apply to pneumatic pump affected facilities as required by §60.5415b(e).

(j) You must perform the reporting as required by §60.5420b(b)(1) and (10) and (b)(11) through (b)(13), as applicable and the recordkeeping as required by §60.5420b(c)(8) and (15) and (c)(10) through (13), as applicable.

**§60.5395b What GHG and VOC standards apply to storage vessel affected facilities?**

Each storage vessel affected facility must comply with the GHG and VOC standards in this section, except as provided in paragraph (e) of this section.

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements of paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for methane and VOC emissions in accordance with §60.5365b(e)(2).

(2) Reduce methane and VOC emissions by 95.0 percent.

(3) Maintain the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy from the storage vessel affected facility without

considering control. Prior to using the uncontrolled actual VOC and methane emission rates for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy and the uncontrolled actual methane emissions have remained less than 14 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual rolling 12-month determination VOC and methane emissions rates each month. The uncontrolled actual VOC and methane emissions must be calculated using a generally accepted model or calculation methodology which account for flashing, working and breathing losses, and the calculations must be based on the actual average throughput, temperature, and separator pressure for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the rolling 12-month emissions determination required in this section indicates that VOC emissions increase to 4 tpy or greater or the methane emissions increase to 14 tpy or greater from your storage vessel affected facility and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;

(iii) The tank battery must be equipped with a closed vent system that meets the requirements of §60.5411b(a) and (c); and

(iv) The vapors collected in paragraphs (b)(1)(ii) and (iii) of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions and that are not located at well sites or centralized production facilities, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(c) *Requirements for storage vessel affected facilities that are removed from service or returned to service.* If you remove a storage vessel affected facility from service or remove a portion of a storage vessel affected facility from service, you must comply with the applicable paragraphs (c)(1) through (4) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in §60.5420b(b)(6)(viii) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) For a portion of a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(2)(i) through (iv) of this section.

(i) You must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(iii) You must submit a notification as required in §60.5420b(b)(8)(viii) in your next annual report, identifying each storage vessel removed from service during the reporting period, the impacted storage vessel affected facility, and the date of its removal from service.

(iv) The remaining storage vessel(s) in the tank battery remain a storage vessel affected facility and must continue to comply with the applicable requirements of paragraphs (a) and (b) of this section.

(3) If a storage vessel identified in paragraph (c)(1)(ii) or (c)(2)(iii) of this section is returned to service, you must determine its affected facility status as provided in §60.5365b(e)(6).

(4) For each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420b(b)(8)(ix), identifying each storage vessel affected facility or portion of a storage vessel affected facility and the date of its return to service.

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410b(j).

(2) You must demonstrate continuous compliance with standards as required by §60.5415b(i).

(3) You must perform the required reporting as required by §60.5420b(b)(1) and (b)(8) and (b)(11) through (b)(13), as applicable and the recordkeeping as required by §60.5420b(c)(7) and (c)(8) through (13), as applicable.

(e) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

**§60.5397b What GHG and VOC standards apply to fugitive emissions components affected facilities?**

This section applies to fugitive emissions components affected facilities. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce fugitive emissions of methane and VOC. The requirements of this section are independent of the closed vent system and cover requirements of §60.5411b.

(a) You must monitor all fugitive emissions components in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must demonstrate initial compliance in accordance with paragraph (i) of this section. You must keep records in accordance with paragraph (j) of this section and report in accordance with paragraph (k) of this section. You must meet the requirements for well closures in accordance with paragraph (l) of this section.

(b) You must develop a fugitive emissions monitoring plan that covers all fugitive emissions components affected facilities within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Your fugitive emissions monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.*, Method 21 of appendix A-7 to this part or optical gas imaging and meeting the requirements of paragraphs (c)(7)(i) through (vii) of this section).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification, and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitive emissions monitoring program with optical gas imaging, fugitive emissions are defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of $\leq$60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator’s maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.,* steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) through (iii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 of appendix A-7 of this part a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) *Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 of this part.* For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) *Procedures for conducting surveys.* At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 of appendix A-7 of this part, including Section 8.3.1.

(iii) *Procedures for calibration.* The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. At a minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 of this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (c)(8)(iii)(A) of this section. Corrective action for drift assessments is specified in paragraphs (c)(8)(iii)(B) and (C) of this section.

(A) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(B) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(C) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, at a minimum, as applicable.

(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

(2) If you are using Method 21 of appendix A-7 of this part, your plan must include a list of fugitive emissions components to be monitored and method for determining the location of fugitive emissions components to be monitored in the field (*e.g.,* tagging, identification on a process and instrumentation diagram, etc.).

(3) Your fugitive emissions monitoring plan must include the written plan developed for all of the fugitive emissions components designated as difficult-to-monitor in accordance with paragraph (g)(2) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(3) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.

(f) *Initial monitoring survey*. You must conduct an initial monitoring survey using visual, audible, olfactory, or any other detection methods at single wellhead only sites and small sites; and using optical gas imaging or Method 21 of appendix A-7 of this part for wellhead only well sites with two or more wellheads, well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(ii)(A), (B), (C), or (D) of this section, and compressor station sites, within 90 days of the startup of production, for each fugitive emissions components affected facility or by **[INSERT DATE 90 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** whichever is later. For a modified or reconstructed fugitive emissions components affected facility, the initial monitoring survey must be conducted within 90 days of the startup of production for each fugitive emissions components affected facility after the modification or reconstruction or by **[INSERT DATE 90 DAYS AFTER PUBLICATION AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later. Notwithstanding the preceding deadlines, for each fugitive emissions components affected facility located on the Alaskan North Slope, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the fugitive emissions components affected facility, or by the following June 30, whichever is latest.

(g) *Monitoring frequency*. A monitoring survey of each fugitive emissions components affected facility must be performed as specified in paragraph (g)(1) of this section, with the exceptions noted in paragraphs (g)(2) through (4) of this section. Monitoring for fugitive emissions components affected facilities located at well sites and centralized production facilities that have wells located onsite must continue at the specified frequencies in paragraphs (g)(1)(i), (ii), (iii) and (v) of this section until the well closure requirements of paragraph (l) of this section are completed.

(1) A monitoring survey of the fugitive emissions components affected facilities must be conducted using the methods and at the frequencies specified in paragraphs (g)(1)(i) through (v) of this section.

(i) A monitoring survey of the fugitive emissions component affected facilities located at single wellhead only well sites and small well sites must be conducted at least quarterly using visual, audible, olfactory, or any other detection method after the initial survey, except as specified in paragraph (g)(1)(v) of this section. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(ii) A monitoring survey of the fugitive emissions components affected facilities located at wellhead only well sites with two or more wellheads must be conducted in accordance with paragraphs (g)(1)(ii)(A) and (B) of this section, except as specified in paragraph (g)(1)(v) of this section.

(A) A monitoring survey must be conducted at least quarterly using visual, audible, olfactory, or any other detection method after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least semiannually using optical gas imaging or Method 21 of appendix A-7 of this part after the initial survey. Consecutive semiannual surveys must be conducted at least 4 months apart and no more than 7 months apart.

(iii) A monitoring survey of the fugitive emissions components affected facilities located at well sites or centralized production facilities that contain the major production and processing equipment specified in paragraphs (g)(1)(iii)(A), (B), (C), or (D) must be conducted at the frequencies in paragraphs (g)(1)(iii)(E) and (F) of this section, except as specified in paragraph (g)(1)(v) of this section.

(A) One or more controlled storage vessels or tank batteries.

(B) One or more control devices.

(C) One or more natural gas-driven pneumatic controllers.

(D) Two or more pieces of major production and processing equipment not specified in paragraphs (g)(1)(ii)(A) through (C).

(E) A monitoring survey must be conducted at least bimonthly using visual, audible, olfactory, or any other detection method after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(F) A monitoring survey must be conducted at least quarterly using optical gas imaging or Method 21 of appendix A-7 of this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(iv) A monitoring survey of the fugitive emissions components affected facility located at a compressor station must be conducted at the frequencies in paragraphs (g)(1)(iv)(A) and (B) of this section, except as specified in paragraph (g)(1)(v) of this section,

(A) A monitoring survey must be conducted at least monthly using visual, audible, olfactory, or any other detection method after the initial survey. Any indications of fugitive emissions using these methods are considered fugitive emissions that must be repaired in accordance with paragraph (h) of this section.

(B) A monitoring survey must be conducted at least quarterly using optical gas imaging or Method 21 of appendix A-7 of this part after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(v) A monitoring survey of the fugitive emissions components affected facility located on the Alaska North Slope must be conducted using optical gas imaging of this part or Method 21 of appendix A-7 of this part at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) If you are using Method 21 of appendix A-7 of this part, fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(2)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(3) If you are using Method 21 of appendix A-7 of this part, fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to

immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(4) The requirements of paragraph (g)(1)(ii) and (iii) of this section are waived for any fugitive emissions components affected facility 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. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(1)(ii) and (iii) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made in accordance with paragraphs (h)(1)(i) and (ii) of this section.

(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.

(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than 15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and 30 calendar days after the first attempt at repair as required in paragraph (h)(1)(ii) of this section.

(3) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(4) Each identified source of fugitive emissions must be resurveyed to complete repair according to the requirements of paragraphs (h)(4)(i) through (v) of this section, to ensure that there are no fugitive emissions.

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A-7 of this part or optical gas imaging, except as specified in paragraph (h)(4)(v) of this section.

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

(iii) Operators that use Method 21 of appendix A-7 of this part to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 of this part are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21 of appendix A-7 of this part.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(4)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(v) For fugitive emissions identified using visual, audible, or olfactory detection methods, the operator may resurvey using those same methods, Method 21 of appendix A-7 of this part, or optical gas imaging. For operators that use visual, audible, or olfactory detection methods, a fugitive emissions component is repaired when there are no indications of fugitive emissions using these methods.

(i) You must demonstrate initial compliance with the standards that apply to fugitive emissions components affected facilities as required by §60.5410b(k).

(j) You must demonstrate continuous compliance with the standards that apply to fugitive emissions components affected facilities as required by §60.5415b(l).

(k) You must comply with the reporting requirements as specified in §60.5420b(b)(1) and (9), and the recordkeeping requirements as specified in §60.5420b(c)(16).

(l) *Well closure requirements*. You must complete the requirements specified in paragraphs (l)(1) through (4) of this section.

(1) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site as specified in §60.5420b(a)(4)(i). The well closure plan must include, at a minimum, the information specified in paragraphs (l)(1)(i) through (iii) of this section.

(i) Description of the steps necessary to close all wells at the well site, including permanent plugging of all wells;

(ii) Description of the financial requirements and disclosure of financial assurance to complete closure; and

(iii) Description of the schedule for completing all activities in the well closure plan.

(2) You must submit a notification as specified in §60.5420b(a)(4)(ii) of intent to close the well site to the Administrator 60 days before you begin well closure activities.

(3) You must conduct a survey of the well site using optical gas imaging, including each closed well, after completing all well closure activities outlined in the well closure plan specified in paragraph (l)(1) of this section. If any emissions are imaged by the optical gas imaging instrument, then you must take steps to eliminate those emissions and you must resurvey the source of emissions. You must repeat steps to eliminate emissions and resurvey the source of emissions until no emissions are imaged by the optical gas imaging instrument. You must update the well closure plan specified in paragraph (l)(1) of this section to include the video of the optical gas imaging survey demonstrating closure of all wells at the site.

(4) You must maintain the records specified in §60.5420b(c)(14) and submit the reports specified in §60.5420b(b)(9).

**§60.5398b What alternative GHG and VOC standards apply to fugitive emissions components affected facilities and covers and closed vent systems?**

This section provides alternative GHG and VOC standards for fugitive emissions components affected facilities in §60.5397b and alternative initial and continuous compliance requirements for covers and closed vent systems in §60.5416b. If you choose to demonstrate compliance with the alternative GHG and VOC standards through periodic screening, you are subject to the requirements in paragraph (b) of this section. If you choose to demonstrate compliance through a continuous monitoring system, you are subject to the requirements in paragraph (c) of this section. The technology used for periodic screenings under paragraph (b) of this section or continuous monitoring under paragraph (c) of this section must be approved in accordance with paragraph (d) of this section.

(a) *Notification.* If you choose to demonstrate compliance with the alternative GHG and VOC standards in either paragraph (b) or (c) of this section, you must notify the Administrator of adoption of the alternative standards in the first annual report following implementation of the alternative standards, as specified in §60.5424b(a). Once you have implemented the alternative standards, you must continue to comply with the alternative standards.

(b) *Periodic Screening.* You may choose to demonstrate compliance for your fugitive emissions components affected facility and your covers and closed vent systems through periodic screenings using a technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using periodic screenings, you must comply with the requirements in paragraphs (b)(1) through (5) of this section and comply with the recordkeeping and reporting requirements in §60.5424b.

(1) You must develop a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at each site where the periodic screening will be used to demonstrate compliance. You may develop a site-specific fugitive emissions monitoring plan, or you may include multiple sites that you own or operate in one plan. At a minimum, the fugitive emissions monitoring plan must contain the information specified in paragraphs (b)(1)(i) through (viii) of this section.

(i) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum of 1983.

(ii) Identification of the approved alternative test method(s) used for the periodic screening.

(iii) Identification of and contact information for the entity that will be performing the periodic screening.

(iv) Frequency for conducting periodic screenings, based on the approval of the alternative test method(s) used.

(v) Procedures for conducting monitoring surveys required by paragraphs (b)(3)(ii) and (b)(4)(ii) of this section. At a minimum, your monitoring plan must include the information required by §60.5397b(c)(2), (3), (7), and (8) and §60.5397b(d), as applicable. The provisions of §60.5397b(d)(3) do not apply for purposes of conducting monitoring surveys required by (b)(4)(ii) of this section.

(vi) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.

(vii) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.

(viii) Records that will be kept and the length of time records will be kept.

(2) You must conduct the initial screening of your site according to the timeframes specified in (b)(2)(i) through (v) of this section.

(i) Within 90 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site.

(ii) Within 90 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.

(iii) Within 90 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site.

(iv) Within 90 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.

(v) No later than the final date by which the next monitoring survey required by §60.5397b(g)(1)(i) through (iv) would have been required to be conducted if you were previously complying with the requirements in §60.5397b and §60.5416b.

(3) The required frequencies for conducting periodic screenings are listed in Tables 1 and 2 of this subpart. You must choose the appropriate frequency for conducting periodic screenings based on the minimum detection threshold of the screening technology in the approved alternative test method(s) selected to conduct the periodic screenings. Use of Table 1 or 2 is based on the required frequency for conducting monitoring surveys in §60.5397b(g)(1)(i) through (iv).

(i) You must choose the appropriate frequency for conducting periodic screenings based on the minimum detection threshold of the screening technology in the approved alternative test method(s) selected to conduct the periodic screenings.

(ii) If Table 1 or 2 of this subpart requires you to perform an annual OGI survey, you must conduct an initial OGI survey no later than 12 calendar months after conducting the initial screening survey in paragraph (b)(2) of this section. Each subsequent OGI survey must be conducted no later than 12 calendar months after the previous OGI survey was conducted. Each identified source of fugitive emissions during the OGI survey shall be repaired in accordance with §60.5397b(h).

(iii) If you are required to conduct a monitoring survey in accordance with paragraph (b)(4)(ii) of this section prior to the date that your next OGI survey under paragraph (b)(3)(ii) of this section is due, the monitoring survey under paragraph (b)(4)(ii) of this section can be used to fulfill the requirements of paragraph (b)(3)(ii) of this section. If you use a survey under paragraph (b)(4)(ii) of this section to fulfill the annual OGI survey requirement, the next OGI survey is required to be conducted no later than 12 calendar months after the date of the survey conducted under paragraph (b)(4)(ii) of this section.

(4) You must repair each identified source of emissions in accordance with paragraphs (b)(4)(i) through (iv) of this section.

(i) You must receive the results of the periodic screening no later than 5 calendar days after the screening occurs.

(ii) If the results of the periodic screening in paragraph (b)(4)(i) of this section indicate a confirmed detection of emissions from an affected facility, you must take the actions listed in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) You must conduct a monitoring survey of the entire fugitive emissions components affected facility following the procedures in your fugitive emissions monitoring plan. During the survey, you must observe each fugitive emissions component for fugitive emissions.

(B) You must inspect all covers and closed vent system(s) with optical gas imaging or Method 21 of appendix A-7 of this part in accordance with the requirements in §60.5416b(b)(2) and (3), as applicable.

(C) You must conduct a visual inspection of the closed vent system or cover to identify if there are any defects, as defined in §60.5416b(a)(1)(ii), §60.5416b(a)(2)(iii), or §60.5416b(a)(3)(i), as applicable.

(iii) You must repair all sources of fugitive emissions in accordance with §60.5397b(h) and all leaks or defects of covers and closed vent systems in accordance with §60.5416b(b)(4), except as specified in this paragraph (b)(4)(iii). Except as allowed by §60.5397b(h)(3) and §60.5416b(b)(5), all repairs must be completed, including the resurvey verifying the repair, within 30 days of receiving the results of the periodic screening in paragraph (b)(4)(i) of this section.

(iv) If the results of the periodic screening in paragraph (b)(4)(i) of this section indicate a confirmed detection at an affected facility, and the ground-based monitoring survey and inspections required by paragraph (b)(4)(ii) of this section demonstrate the confirmed detection was caused by a failure of a control device subject to §60.5413b, you must initiate a root cause analysis to determine the cause of such failure and to determine appropriate corrective action within 24 hours of the monitoring survey and inspection.

(5) If the results of the inspections required in paragraph (b)(4)(ii) of this section indicate that there is a leak or defect in your cover or closed vent system, you must perform a root cause analysis to determine the cause of emissions from your cover or closed vent system within 5 days completing the inspection. The root cause analysis must include a determination as to whether the system was operated outside of the engineering design analyses and whether updates are necessary for the cover or closed vent system.

(6) You must maintain the records as specified in §60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and 60.5424b(c).

(7) You must submit the reports as specified in §60.5424b.

(c) *Continuous Monitoring*. You may choose to demonstrate compliance for your fugitive emissions components affected facility and your cover and closed vent system through continuous monitoring using a technology approved in accordance with paragraph (d) of this section. If you choose to demonstrate compliance using continuous monitoring, you must comply and develop a monitoring plan consistent with the requirements in paragraphs (c)(1) through (9) of this section and comply with the recordkeeping and reporting requirements in §60.5424b.

(1) For the purpose of this section, continuous monitoring means the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block.

(i) The sensitivity of the system must be such that it can at least measure an order of magnitude less than the action-level defined in paragraph (c)(4)(iii) of this section.

(ii) The health of the devices used within the continuous monitoring system must be confirmed for power and connectivity at least twice every six-hour block.

(iii) The continuous monitoring system must continuously collect data as specified in paragraph (c)(1) of this section, except as specified in paragraphs (c)(1)(ii)(A) through (D) of this section:

(A) The rolling 12-month average operational downtime of the continuous monitoring system must be less than or equal to 10 percent.

(B) Operational downtime of the continuous monitoring system is defined as a period of time for which any monitor fails to collect or transmit data as specified in paragraph (c)(1) of this section or any monitor is out-of-control as specified in paragraph (c)(1)(ii)(C) of this section.

(C) A monitor is out-of-control if it fails ongoing quality assurance checks, as specified in the alternative test method approved under paragraph (d) of this section, or if the monitor output is outside of range. The beginning of the out-of-control period is defined as the time of the failure of the quality assurance check. The end of the out-of-control period is defined as the time when either the monitor passes a subsequent quality assurance check, or a new monitor is installed. The out-of-control period for a monitor outside of range starts at the time when the monitor first reads outside of range and ends when the monitor reads within range again.

(D) The downtime for the continuous monitoring system must be calculated each calendar month. Once 12 months of data are available, at the end of each calendar month, you must calculate the 12-month average by averaging that month with the previous 11 calendar months. You must determine the rolling 12-month average by recalculating the 12-month average at the end of each month.

(2) You must develop a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at each site where continuous monitoring will be used to demonstrate compliance. At a minimum, the fugitive emissions monitoring plan must contain the information specified in paragraphs (c)(2)(i) through (xi) of this section.

(i) Identification of each site to be monitored through continuous monitoring, including latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of four decimals of a degree using the North American Datum of 1983.

(ii) Identification of the approved alternative test method(s) used for the continuous monitoring, including the detection principle; the manufacturer, make, and model; instrument manual, if applicable; and the manufacturer's recommended maintenance schedule.

(iii) If the continuous monitoring system is administered through a third-party provider, contact information where the provider can be reached 24-hours a day.

(iv) Number and location of monitors. If the continuous monitoring system uses open path technology, you must identify the location of any reflectors used. These locations should be identified by latitude and longitude coordinates in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum of 1983.

(v) Discussion of system calibration requirements, including but not limited to, the calibration procedures and calibration schedule for the detection systems and meteorology systems.

(vi) Identification of critical components and infrastructure (*e.g.*, power, data systems) and procedures for their repairs.

(vii) Procedures for out-of-control periods.

(viii) Procedures for determining when a fugitive emissions event is detected by the continuous monitoring technology.

(ix) Procedures and timeframes for identifying and repairing fugitive emissions components, covers, and closed vent systems from which emissions are detected.

(x) Procedures and timeframes for verifying repairs for fugitive emissions components, covers, and closed vent systems.

(xi) Records that will be kept and the length of time records will be kept.

(3) You must install and begin conducting monitoring with your continuous monitoring system according to the timeframes specified in (c)(3)(i) through (v) of this section.

(i) Within 120 days of the startup of production for each fugitive emissions components affected facility and storage vessel affected facility located at a new well site.

(ii) Within 120 days of the startup of a new compressor station for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station.

(iii) Within 120 days of the startup of production after modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a well site.

(iv) Within 120 days of modification for each modified fugitive emissions components affected facility and storage vessel affected facility at a compressor station.

(v) No later than the final date by which the next monitoring survey required by §60.5397b(g)(1)(i) through (iv) would have been required to be conducted if you were previously complying with the requirements in §60.5397b and §60.5416b.

(4) You are subject to the following action-levels as specified in paragraphs (c)(4)(i) and (ii) of this section for any affected facilities located at a well site, centralized production facility, or compressor station.

(i) For affected facilities located at a wellhead only well site, the action levels are as follows.

(A) The rolling 90-day average action-level is 1.2 kg/hr (2.6 lbs/hr).

(B) The rolling 7-day average action level is 15 kg/hr (34 lbs/hr).

(ii) For well sites with major production and processing equipment (including small well sites), centralized production facilities, and compressor stations, the action levels are as follows.

(A) The rolling 90-day average action-level is 1.6 kg/hr (3.6 lbs/hr).

(B) The rolling 7-day average action level is 21 kg/hr (46 lbs/hr).

(5) Calculate the emission rates from your site according to paragraphs (c)(5)(i) through (iii) of this section. Compare the emission rates calculated in this paragraph (c)(5) to the appropriate action levels in paragraph (c)(4) of this section to determine whether you have exceeded an action level.

(i) Each calendar day, calculate the daily average mass emission rate (*i.e.*, kg/hr) from your continuous monitoring system.

(ii) At the end of the calendar day, calculate the 7-day mass emission rate average by averaging the mass emission rate from that day with the previous 6 calendar days. Determine the 7-day rolling average by recalculating the 7-day average each calendar day.

(iii) At the end of each calendar day, calculate the 90-day mass emission rate average by averaging the mass emission rate from that day with the previous 89 days. Determine the 90-day rolling average by recalculating the 90-day average each calendar day.

(6) Within 5 days of determining that either of your action levels in paragraph (c)(4) of this section has been exceeded, you must initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action.

(i) The root cause analysis and initial corrective action analysis shall be completed, and initial corrective actions taken no later than 5 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(B) or (c)(4)(ii)(B) of this section.

(ii) The root cause analysis and initial corrective action analysis shall be completed and initial corrective actions taken no later than 30 days after determining there is an exceedance of the action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section.

(7) If, upon completion of the initial corrective actions required under paragraph (c)(6) of this section, the continuous monitor readings are not below the action level in paragraph (c)(4)(i)(A) or (c)(4)(ii)(A) of this section for the next 30-day sampling period or below the action level in paragraph (c)(4)(i)(B) or (c)(4)(ii)(B) of this section for the next 24-hour sampling period or if all corrective action measures identified to reduce methane and VOC emissions require more than 30 days to implement, you must develop a corrective action plan. The

beginning of the 24-hour and/or 30-day sampling period starts in the hour following completion of the initial corrective actions. The corrective action plan must describe the corrective action(s) completed to date, additional measures that you propose to employ to reduce methane emissions below the action level, and a schedule for completion of these measures. You must submit the corrective action plan to the Administrator within 60 days of the initial exceedance.

(8) You must maintain the records as specified in §60.5420b(c)(4) through (c)(7), (c)(14) and (c)(15), and 60.5424b(e).

(9) You must submit the reports as specified in §60.5420b(b)(1), and (b)(4) through (10) and §60.5424b.

(d) *Alternative Test Method.* Any alternative test method used to meet the requirements specified in paragraphs (b) or (c) of this section must be approved by the Administrator as specified in §60.8(b) and according to the provisions in this paragraph (d). Approval of an alternative test method will include consideration of the combination of the measurement technology and the standard protocol for its operation. Any entity meeting the requirements in paragraph (d)(2) of this section may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraph (d)(3) of this section. Approved alternative test methods that are broadly applicable will be posted on the EPA's Emission Measurement Center webpage (*https://www.epa.gov/emc/oil-andgas-approved-alternative-test-methods*). Any owner or operator that meets the specific applicability for the alternative test method, as outlined in the alternative test method, may use the alternative test method to comply with the requirements of paragraph (b) or (c) of this section, as applicable, in lieu of the requirements for fugitive emissions components affected facilities in §60.5397b and covers and closed vent systems in §60.5416b.

(1) A request for an alternative test method, along with the required supporting information, must be submitted to: Leader, Measurement Technology Group, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency (Mail Code E143-02), Research Triangle Park, NC 27711. If your submittal includes information claimed to be CBI, submit the portion of the information claimed as CBI to the OAQPS CBI office. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov and should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Leader, Measurement Technology Group. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) The Administrator will acknowledge receipt of the request within 14 days of receipt.

(ii) The Administrator will complete an initial review for completeness within 90 days of receipt. If the request is deficient, meaning the requirements in paragraphs (d)(2) and (3) were not met, the request will be denied, and the Administrator will notify the requestor in writing. The requestor may choose to revise the information and submit a new request for an alternative test method.

(iii) The Administrator will determine whether the requested alternative test method is adequate for indicating compliance within 270 days of receipt of the request and issue either an approval or disapproval in writing to the requestor. Approvals may be considered site-specific or more broadly applicable. Broadly applicable alternative test methods and approval letters will be posted at *https://www.epa.gov/emc/oil-andgas-approved-alternative-test-methods*. If the Administrator fails to provide the requestor a decision on approval or disapproval within 270 days, the alternative test method will be given conditional approval status and posted on this same webpage. If the Administrator finds any deficiencies in the request and disapproves the request in writing, the owner or operator may choose to revise the information and submit a new request for an alternative test method.

(iv) If the Administrator finds reasonable grounds to dispute the results obtained by any alternative test method for the purposes of demonstrating compliance with a relevant standard, the Administrator may require you to demonstrate compliance according to §60.5397b for fugitive emissions components affected facilities and §60.5416b for covers and closed vent systems.

(2) Any entity may submit an alternative test method for consideration, so long as you meet the requirements in paragraphs (d)(2)(i) through (iv) of this section.

(i) An entity is limited to any individual or organization located in or that has representation in the United States.

(ii) If an entity is not considered an owner or operator of an applicable facility, the provisions of paragraphs (d)(2)(ii)(A) and (B) apply.

(A) The entity must directly represent the underlying technology, and

(B) The underlying technology must have been applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally.

(iii) The underlying technology or technologies must be commercially available, meaning that it has been sold, leased, or licensed, or offered for sale, lease, or license to the general public.

(iv) The entity must be able to provide and submit to the Administrator the information required in paragraph (d)(3) of this section.

(3) At a minimum, the request must contain the information specified in paragraphs (3)(i) through (v) of this section.

(i) The desired applicability of the technology (*i.e.*, site-specific, basin-specific or broadly applicable across the sector).

(ii) Detailed description of the measurement systems including the methane detection technology, additional measurements collected, and example calculations and/or algorithms.

(iii) Supporting information verifying that the technology meets the defined detection threshold(s) defined in paragraph (b) and/or (c) of this section, including supporting data to demonstrate the sensitivity of the measurement technology as applied in the field.

(iv) Standard operating procedures consistent with EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control (*i.e.*, initial and ongoing calibration procedures, data quality indicators, and data quality objectives).

(v) Detailed description of the alternative testing procedure(s), preferably in the format described at *https://www.epa.gov/sites/default/files/2020-08/documents/gd-045.pdf*. The detailed description must address all key elements of the requested method(s) and should include objectives to ensure the detection threshold(s) required in paragraph (d)(3)(iii) of this section are maintained, including procedures for a daily verification check of the measurement sensitivity under field conditions.

**§60.5399b What are the alternative means of emission limitations for GHG and VOC emissions from well completions, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?**

This section provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, fugitive emissions components and process unit equipment affected facilities. This section also provides procedures for the submittal and approval of alternative fugitive emissions standards based on programs under state, local, or tribal authorities for the fugitive emissions components affected facility. Paragraphs (a) through (d) of this section outline the procedure for submittal and approval of alternative means of emission limitation for methane and VOC. Paragraphs (e) through (i) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. The requirements for a monitoring plan specified in §60.5397b(c) and (d) apply to the alternative fugitive emissions standards in this section.

(a) *Alternative means of emission limitation.* If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under §60.5375b, §60.5397b, §60.5400b, or §60.5401b, the Administrator will publish, in the *Federal Register*, a notice permitting the use of that alternative means for the purpose of compliance with §60.5375b, §60.5397b, §60.5400b, or §60.5401b. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(b) *Notice.* Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) *Evaluation guidelines*. Determination of equivalence to the design, equipment, work practice, or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative means of emission limitation achieves emission reductions that are at least equivalent to the emission reductions that would be achieved by complying with the relevant standards. At a minimum, the application must include the following information:

(i) Details of the specific equipment or components that would be included in the alternative.

(ii) A description of the alternative work practice, including, as appropriate, the monitoring method, monitoring instrument or measurement technology, and the data quality indicators for precision and bias.

(iii) The method detection limit of the technology, technique, or process and a description of the procedures used to determine the method detection limit. At a minimum, the applicant must collect, verify, and submit field data encompassing seasonal variations to support the determination of the method detection limit. The field data may be supplemented with modeling analyses, controlled test site data, or other documentation.

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

(v) Frequency of measurements. For continuous monitoring techniques, the minimum data availability.

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

(vii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in this subpart.

(2) For each technology, technique, or process for which a determination of equivalency is requested, the application must provide a demonstration that the emission reduction achieved by the alternative means of emission limitation is at least equivalent to the emission reduction that would be achieved by complying with the relevant standards in this subpart.

(d) *Approval of alternative means of emission limitation.* Any alternative means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(e) *Alternative fugitive emissions standards.* If, in the Administrator's judgment, an alternative fugitive emissions standard will achieve a reduction in methane and VOC emissions at least equivalent to the reductions achieved under §60.5397b, the Administrator will publish, in the *Federal Register*, a notice permitting use of the alternative fugitive emissions standard for the purpose of compliance with §60.5397b. The authority to approve alternative fugitive emissions standards is retained by the Administrator and shall not be delegated to States under section 111(c) of the CAA.

(f) *Notice.* Any notice under paragraph (e) of this section will be published only after notice and an opportunity for public hearing.

(g) *Evaluation guidelines*. Determination of alternative fugitive emissions standards to the design, equipment, work practice, or operational requirements of §60.5397b will be evaluated by the following guidelines:

(1) The monitoring instrument, including the monitoring procedure;

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

(h) *Approval of alternative fugitive emissions standard.* Any alternative fugitive emissions standard approved under this section shall:

(1) Constitute a required design, equipment, work practice, or operational standard within the meaning of section 111(h)(1) of the CAA; and

(2) Be made available for use by any owner or operator in meeting the relevant standards and requirements established for affected facilities under §60.5397b.

(i) *Notification.* (1) An owner or operator must notify the Administrator of adoption of the alternative fugitive emissions standards within the first annual report following implementation of the alternative fugitive emissions standard, as specified in §60.5420b(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in §60.5420b(b)(9)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

**§60.5400b What GHG and VOC standards apply to process unit equipment affected facilities?**

This section applies to process unit equipment affected facilities located at an onshore natural gas processing plant. You must comply with the requirements of paragraphs (a) through (l) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in §60.5402b. As an alternative to the standards in this section, you may comply with the requirements in §60.5401b.

(a) *General standards.* You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least

equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 of this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16, E169-16, or E260-96 (incorporated by reference as specified in §60.17).

(b) *Monitoring surveys.* You must monitor for leaks using optical gas imaging in accordance with appendix K of this part, unless otherwise specified in paragraphs (c) or (d) of this section.

(1) Monitoring surveys must be conducted bimonthly.

(2) Any emissions observed using optical gas imaging are defined as a leak.

(c) *Additional requirements for pumps in light liquid service.* In addition to the requirements in paragraph (b), you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal, except as specified in paragraphs (c)(3) and (4) of this section. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (c)(1) or (2) of this section.

(1) Monitor the pump within 5 days using the methods specified in §60.5403b. A leak is detected if any emissions are observed using optical gas imaging or if an instrument reading of 2,000 ppm or greater is provided using Method 21 of appendix A-7 of this part.

(2) Designate the visual indications of liquids dripping as a leak and repair the leak as specified in paragraph (h) of this section.

(3) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (f) of this section, it is exempt from the weekly inspection requirements in paragraph (c) of this section.

(4) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (c) of this section, provided that each pump is visually inspected as often as practicable and at least bimonthly.

(d) *Additional requirements for pressure relief devices in gas/vapor service.* In addition to the requirements in paragraph (b) of this section, you must monitor each pressure relief device as specified in paragraphs (d)(1) of this section, except as specified in paragraphs (d)(2) and (d)(3) of this section.

(1) You must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks using the methods specified in §60.5403b. A leak is detected if any emissions are observed using optical gas imaging or if an instrument reading of 500 ppm or greater is provided using Method 21 of appendix A-7 of this part.

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is

sooner, instead of within 5 calendar days as specified in paragraph (d)(1) of this section. No pressure relief device described in this paragraph may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(3) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph (f) of this section is exempt from the requirements of paragraph (d)(1) of this section.

(e) *Open-ended valves or lines.* Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (e)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by visual, audible, olfactory, or any other detection method, a leak is detected.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system as specified in paragraphs (e) and (e)(2) through (3) of this section are exempt from the requirements of this section.

(f) *Closed vent systems and control devices.* Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§60.5412b and 60.5417b.

(g) *Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.* If evidence of a potential leak is found at any time by visual, audible, olfactory, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (h) of this section.

(h) *Repair requirements.* When a leak is detected, you must comply with the requirements of paragraphs (h)(1) through (6) of this section, except as provided in paragraph (h)(7) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected. A first attempt at repair is not required if the leak is detected using optical gas imaging and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (h)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) First attempts at repair for valves in gas/vapor, light liquid, or heavy liquid service include, but are not limited to, the practices described in paragraphs (h)(2)(ii)(A) through (D) of this section, where practicable.

(A) Tightening of bonnet bolts.

(B) Replacements of bonnet bolts.

(C) Tightening of packing gland nuts.

(D) Injection of lubricant into lubricated packing.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraphs (h)(4), (5) and (6) of this section.

(4) Repair for visual indications of liquids dripping for pumps in light liquid service may be made by eliminating visual indications of liquids dripping within 5 calendar days of detection.

(5) Repair for visual, audible, or olfactory or other indication of a leak for open-ended valves or lines; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service may be made by eliminating the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(6) Delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown or as specified in paragraphs (h)(6)(i) through (v) of this section. Repair of this equipment shall occur before the

end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(i) Delay of repair of equipment is allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors is allowed if the conditions in paragraphs (h)(6)(ii)(A) and (B) are met.

(A) You must demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (f) of this section.

(iii) Delay of repair for pumps is allowed if the conditions in paragraphs (h)(6)(iii)(A) and (B) are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) Delay of repair beyond a process unit shutdown is allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive bimonthly monitoring results show no leak remains.

(i) *Initial compliance*. You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by §60.5410b(h).

(j) *Continuous compliance*. You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by §60.5415b(j).

(k) *Reporting.* You must perform the reporting requirements as specified in §60.5420b(b)(1) and (11) and §60.5422b.

(l) *Recordkeeping.* You must perform the recordkeeping requirements as specified in §60.5420b(c)(8), (10), and (12) and §60.5421b.

**§60.5401b What are the alternative GHG and VOC standards for process unit equipment affected facilities?**

This section provides alternative standards for process unit equipment affected facilities located at an onshore natural gas processing plant. You may choose to comply with the standards in this section instead of the requirements in §60.5400b. For purposes of the alternative standards provided in this section, you must comply with the requirements of paragraphs (a) through (m) of this section to reduce methane and VOC emissions from equipment leaks, except as provided in §60.5402b.

(a) *General standards.* You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device used to comply with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.

(1) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5399b.

(2) Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of appendix A-6 of this part. Alternatively, if the piece of equipment is in wet gas service, you may choose to determine the methane and VOC content of

the stream is below the detection limit of the methods described in ASTM E168-16, E169-16, or E260-96 (incorporated by reference as specified in §60.17).

(b) *Pumps in light liquid service.* You must monitor each pump in light liquid service monthly to detect leaks by the methods specified in §60.5403b, except as provided in paragraphs (b)(2) through (4). A leak is defined as an instrument reading of 2,000 ppm or greater. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (b)(2) through (4) of this section.

(1) In addition to the requirements in paragraph (b), you must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, you must follow the procedure specified in either paragraph (b)(1)(i) or (ii) of this section.

(i) Monitor the pump within 5 days using the methods specified in §60.5403b. A leak is defined as an instrument reading of 2,000 ppm or greater.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak as specified in paragraph (i) of this section.

(2) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements in paragraph (b) of this section, provided the requirements specified in paragraphs (b)(2)(i) through (vi) of this section are met.

(i) Each dual mechanical seal system meets the requirements of paragraphs (b)(2)(i)(A), (B), or (C).

(A) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(B) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of paragraph (e) of this section; or

(C) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(ii) The barrier fluid system is in heavy liquid service or does not have the potential to emit methane or VOC.

(iii) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(iv) Each pump is checked according to the requirements in paragraph (b)(1) of this section.

(v) Each sensor meets the requirements in paragraphs (b)(2)(v)(A) through (C) of this section.

(A) Each sensor as described in paragraph (b)(2)(iii) is checked daily or is equipped with an audible alarm.

(B) You determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(C) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (b)(2)(v)(B) of this section, a leak is detected.

(3) Any pump that is designated, as described in §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (b), (b)(1), and (b)(2) of this section if the pump:

(i) Has no externally actuated shaft penetrating the pump housing;

(ii) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background as measured by the methods specified in §60.5403b; and

(iii) Is tested for compliance with paragraph (b)(3)(ii) of this section initially upon designation, annually, and at other times requested by the Administrator.

(4) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph (e) of this section, it is exempt from paragraphs (b), (b)(1) through (3) of this section, and the repair requirements of paragraph (i) of this section.

(5) Any pump that is designated, as described in §60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (b), (b)(1) and (b)(2)(iv) through (vi) of this section if the conditions in paragraph (b)(5)(i) and (ii) are met.

(i) You demonstrate that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (b) of this section; and

(ii) You have a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(6) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph (b)(1) and (b)(2)(iv) of this section, and the daily requirements of paragraph (b)(2)(v) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

(c) *Pressure relief devices in gas/vapor service.* You must monitor each pressure relief device quarterly using the methods specified in §60.5403b. A leak is defined as an instrument reading of 500 ppm or greater above background.

(1) In addition to the requirements in paragraph (c), after each pressure release, you must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks. A leak is detected if an instrument reading of 500 ppm or greater is provided using the methods specified in §60.5403b(b).

(2) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite or within 30 calendar days after a pressure release, whichever is sooner, instead of within 5 calendar days as specified in paragraph (c)(1) of this section.

(3) No pressure relief device described in paragraph (c)(2) of this section may be allowed to operate for more than 30 calendar days after a pressure release without monitoring.

(4) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph (e) of this section is exempt from the requirements of paragraphs (c) and (c)(1) of this section.

(5) Pressure relief devices equipped with a rupture disk are exempt from the requirements of paragraphs (c)(1) and (2) of this section provided you install a new rupture disk upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in paragraph (i)(4) of this section.

(d) *Open-ended valves or lines.* Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d)(4) and (5) of this section. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

(1) If evidence of a leak is found at any time by visual, audible, olfactory, or any other detection method, a leak is detected and must be repaired in accordance with paragraph (i) of this section. A leak is defined as an instrument reading of 500 ppm or greater if Method 21 of appendix A-7 of this part is used.

(2) Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(3) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall remain closed at all other times.

(4) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (d), and (d)(1) through (3) of this section.

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped

or equipped with a double block-and-bleed system as specified in paragraphs (d) and (d)(2) through (3) of this section are exempt from the requirements of this section.

(e) *Closed vent systems and control devices.* Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in §§60.5412b and 60.5417b.

(f) *Valves in gas/vapor and light liquid service.* You must monitor each valve in gas/vapor and in light liquid service quarterly to detect leaks by the methods specified in §60.5403b, except as provided in paragraphs (h)(3) through (5).

(1) A valve that begins operation in gas/vapor service or in light liquid service after the initial startup date for the process unit must be monitored for the first time within 90 days after the end of its startup period to ensure proper installation, except for a valve that replaces a leaking valve and except as provided in paragraphs (h)(3) through (5) of this section.

(2) An instrument reading of 500 ppmv or greater is a leak. You must repair each leaking valve according to the requirements in paragraph (i) of this section.

(3) Any valve that is designated, as described in §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs (f) of this section if the valve:

(i) Has no externally actuating mechanism in contact with the process fluid;

(ii) Is operated with emissions less than 500 ppmv above background as determined by the methods specified in §60.5403b; and

(iii) Is tested for compliance with paragraph (f)(3)(ii) of this section initially upon designation, annually, and at other times requested by the Administrator.

(4) Any valve that is designated, as described in §60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the monitoring requirements of paragraph (f) of this section if the requirements in paragraph (f)(4)(i) and (ii) are met.

(i) You demonstrate that the valve is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (f) of this section; and

(ii) You have a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(5) Any valve that is designated, as described in §60.5421b(b)(14), as a difficult-to-monitor valve is exempt from the monitoring requirements of paragraph (h) of this section if the requirements in paragraph (f)(5)(i) through (iii) are met.

(i) You demonstrate that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(ii) The process unit within which the valve is located has less than 3.0 percent of its total number of valves designated as difficult-to-monitor.

(iii) You have a written plan that requires monitoring of the at least once per calendar year.

(g) *Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.* If evidence of a potential leak is found at any time by visual, audible, olfactory, or any other detection method, you must comply with either paragraph (g)(1) or (2) of this section.

(1) You must monitor the equipment within 5 calendar days by the method specified in §60.5403b and repair any leaks detected according to paragraph (i) of this section. An instrument reading of 10,000 ppmv or greater is defined as a leak.

(2) You must designate the visual, audible, olfactory, or other indication of a leak as a leak and repair the leak according to paragraph (i) of this section.

(h) *Connectors in gas/vapor service and in light liquid service.* You must initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, you are required to monitor only those connectors involved in the process change.

(1) You must monitor all connectors in gas/vapor service and in light liquid service annually, except as provided in §60.5399b, paragraph (e) of this section or paragraph (h)(2) of this section.

(2) Any connector that is designated, as described in §60.5421b(b)(13), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (h) and (h)(1) of this section if the requirements of paragraphs (h)(2)(i) and (ii) are met.

(i) You demonstrate the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (h) and (h)(1) of this section; and

(ii) You have a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and you repair the equipment according to the procedures in paragraph (i) of this section if a leak is detected.

(3) Inaccessible, ceramic, or ceramic-line connectors.

(i) Any connector that is inaccessible or that is ceramic or ceramic-lined (*e.g.*, porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (h) and (h)(1) of this section, from the leak repair requirements of paragraph (i) of this section, and from the recordkeeping and reporting requirements of §§60.5421b and 60.5422b. An inaccessible connector is one that meets any of the specifications in paragraphs (h)(3)(i)(A) through (F) of this section, as applicable.

(A) Buried.

(B) Insulated in a manner that prevents access to the connector by a monitor probe.

(C) Obstructed by equipment or piping that prevents access to the connector by a monitor probe.

(D) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground.

(E) Inaccessible because it would require elevating monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold.

(F) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment.

(ii) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere must be eliminated as soon as practicable.

(4) Connectors which are part of an instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (h)(3) of this section, are not subject to the recordkeeping requirements of 60.5421b(b)(1).

(i) *Repair requirements.* When a leak is detected, comply with the requirements of paragraphs (i)(1) through (5) of this section, except as provided in paragraph (i)(6) of this section.

(1) A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

(2) A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

(i) First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs (i)(2)(i)(A) and (B) of this section, where practicable.

(A) Tightening the packing gland nuts.

(B) Ensuring that the seal flush is operating at design pressure and temperature.

(ii) First attempts at repair for valves in gas/vapor, light liquid, or heavy liquid service include, but are not limited to, the practices described in paragraphs (i)(2)(ii)(A) through (D) of this section, where practicable.

(A) Tightening of bonnet bolts.

(B) Replacements of bonnet bolts.

(C) Tightening of packing gland nuts.

(D) Injection of lubricant into lubricated packing.

(3) Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph (i)(4), (5), or (6) of this section.

(4) Repair for visual indications of liquids dripping for pumps in light liquid service may be made by eliminating visual indications of liquids dripping within 5 calendar days of detection.

(5) Repair for visual, audible, or olfactory or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service may be made by eliminating the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(6) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown or as specified in paragraphs (i)(4)(i) through (v) of this section. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(i) Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

(ii) Delay of repair for valves and connectors will be allowed if the conditions in paragraphs (i)(4)(ii)(A) and (B) are met.

(A) You demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(B) When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph (e) of this section.

(iii) Delay of repair for pumps will be allowed if the conditions in paragraphs (i)(4)(iii)(A) and (B) are met.

(A) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(B) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(iv) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(v) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring results show no leak remains.

(j) *Initial compliance.* You must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by §60.5410b(h).

(k) *Continuous compliance.* You must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by §60.5415b(j).

(l) *Reporting.* You must perform the reporting requirements as specified in §§60.5420b(b)(1), (b)(11), and 60.5422b.

(m) *Recordkeeping.* You must perform the recordkeeping requirements as specified in §60.5412b(c)(8), (c)(10), (c)(12) and §60.5421b.

**§60.5402b What are the exceptions to the GHG and VOC standards for process unit equipment affected facilities?**

(a) You may comply with the following exceptions to the provisions of §§60.5400b(a) and 60.5401b(a), as applicable.

(b) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas may comply with the exceptions specified in paragraphs (b)(1) or (2) of this section.

(1) You may conduct quarterly monitoring instead of bimonthly monitoring as required under §60.5400b(b).

(2) You are exempt from the routine monitoring requirements of §60.5401b(b), (c), (f), and (h), if complying with the alternative standards of §60.5401b.

(c) Pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements §60.5400b(b) and (c) and §60.5401b(b), (c), (f) and (h).

(d) You may use the following provisions instead of §60.5403b(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(e) Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements of §60.5400b(b) through (g), if it is identified as required in §60.5421b(b)(15). Equipment that is in vacuum service is excluded from the requirements of §60.5401b(b) through (g) if it is identified as required in §60.5421b(b)(15).

(f) Equipment that you designate as having the potential to emit methane or VOC less than 300 hrs/yr is excluded from the requirements of §60.5400b(b) through (g) and §60.5401b(b) through (h), if it is identified as required in §60.5421b(b)(16) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment has the potential to emit methane or VOC only during startup and shutdown.

(2) The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

**§60.5403b What test methods and procedures must I use for my process unit equipment affected facilities?**

(a) In conducting the performance tests required in §60.8, you must use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) You must determine compliance with the standards in §60.5401b as follows:

(1) Method 21 of appendix A-7 of this part shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppmv of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppmv greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppmv above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately or equal to 10,000 ppmv. If only one scale on an instrument will be used during monitoring, you need not calibrate the scales that will not be used during that day's monitoring.

(iii) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 of appendix A-7 of this part. For purposes of instrument capability, the leak definition shall be 500 ppmv or greater methane using a FID-based instrument for valves and connectors and 2,000 ppmv methane or greater for pumps . If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific leak definition that would be equivalent to 500 ppmv methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the leak definition would provide equivalent response to your compound of interest).

(2) The instrument must be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. At minimum, you must also conduct precision tests at the interval specified in Method 21 of appendix A-7 of this part, Section 8.1.2, and a calibration drift assessment at the end of each monitoring day. The calibration drift assessment must be conducted as specified in paragraph (b)(2)(i) of this section. Corrective action for drift assessments is specified in paragraphs (b)(2)(ii) and (iii) of this section.

(i) Check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage.

(ii) If a calibration drift assessment shows a negative drift of more than 10 percent, then all equipment with instrument readings between the fugitive emission definition multiplied by (100 minus the percent of negative drift) divided by 100 and the fugitive emission definition that was monitored since the last calibration must be re-monitored.

(iii) If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the fugitive emission definition and below the fugitive emission definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

(c) You shall determine compliance with the no detectable emission standards in §60.5401b(b), (c), and (f) as specified in paragraphs (c)(1) and (2) of this section.

(1) The requirements of paragraph (b) of this section shall apply.

(2) Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppmv for determining compliance.

(d) You shall demonstrate that a piece of equipment is in light liquid service by showing that all of the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference - see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(e) Samples used in conjunction with paragraphs (d), and (e) of this section shall be representative of the process fluid that is contained in or contacts the equipment, or the gas being combusted in the flare.

**§60.5405b What standards apply to sweetening unit affected facilities?**

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an $SO_2$ emission reduction efficiency ($Z_i$) to be determined from Table 3 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an $SO_2$ emission reduction efficiency ($Z_c$) to be determined from Table 4 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(c) You must demonstrate initial compliance with the standards that apply to sweetening unit affected facilities as required by §60.5410b(i).

(d) You must demonstrate continuous compliance with the standards that apply to sweetening unit affected facilities as required by §60.5415b(k).

(e) You must perform the reporting as required by §60.5420b(a)(1), (b)(1) and §60.5423b and the recordkeeping as required by and §60.5423b.

**§60.5406b What test methods and procedures must I use for my sweetening unit affected facilities?**

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of $SO_2$ emissions as required in §60.5405b(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

$Q_a$ = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average $H_2S$ concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= $1.331 \times 10^{-3}$Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= $3.707 \times 10^{-5}$ long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate ($Q_a$) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408b or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the $H_2S$ concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average $H_2S$ concentration (Y) on a dry basis for the run. By multiplying

the result from the Tutwiler procedure by $1.62 \times 10^{-3}$, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial ($Z_i$) and continuous ($Z_c$) reduction efficiencies of $SO_2$ emissions.

(c) You must determine the emission reduction efficiency (R) achieved by the sulfur recovery technology as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_e Q_{sd}/K_1$$

Where:

E = emission rate of sulfur per run, kg/hr.

$C_e$ = concentration of sulfur equivalent ($SO^{2+}$ reduced sulfur), g/dscm (lb/dscf).

$Q_{sd}$ = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

$K_1$ = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration ($C_e$) of sulfur equivalent must be the sum of the $SO_2$ and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test

methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 $m^2$ (54 $ft^2$) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 $m^2$ or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 or 6C of appendix A-4 of this part to determine the $SO_2$ concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by $0.5 \times 10^{-3}$ to convert the results to sulfur equivalent. In place of Method 6 of appendix A of this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(ii) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate ($Q_{sd}$) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged.

(iii) You must use Method 4 of appendix A-2 of this part for moisture content. Alternatively, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

(iv) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 $ft^3$/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppmv reduced sulfur as sulfur must be multiplied by $1.333 \times 10^{-3}$ to convert the results to sulfur equivalent.

(v) You must use Method 16A of appendix A-6 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by $1.333 \times 10^{-3}$ to convert the results to sulfur equivalent.

(iv) You must use EPA Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate ($Q_{sd}$) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

**§60.5407b What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities?**

(a) If your sweetening unit affected facility is subject to the provisions of §60.5405b(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The $H_2S$ concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406b(b)(1). The Administrator may require you to demonstrate that the $H_2S$ concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the $H_2S$ concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in §60.5406b(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the $H_2S$ concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405b(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of $SO_2$ in the gases discharged to the atmosphere. The $SO_2$ emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405b(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405b(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405b, the temperature of the gas leaving the

incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as $SO_2$) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved using a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as $SO_2$ equivalent in the gases discharged to the atmosphere. The $SO_2$ equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405b(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406b(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of $H_2S$ expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

$K_2$ = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see §60.17) may be used.

**§60.5408b What is an optional procedure for measuring hydrogen sulfide in acid gas – Tutwiler Procedure?**

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and $H_2S$ concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100- or 500-ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains $H_2S$ per cubic feet of gas.

(3) *Starch solution.* Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure*. Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions start to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains $H_2S$ per 100 cubic feet of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with $H_2S$-free gas or air, is required.

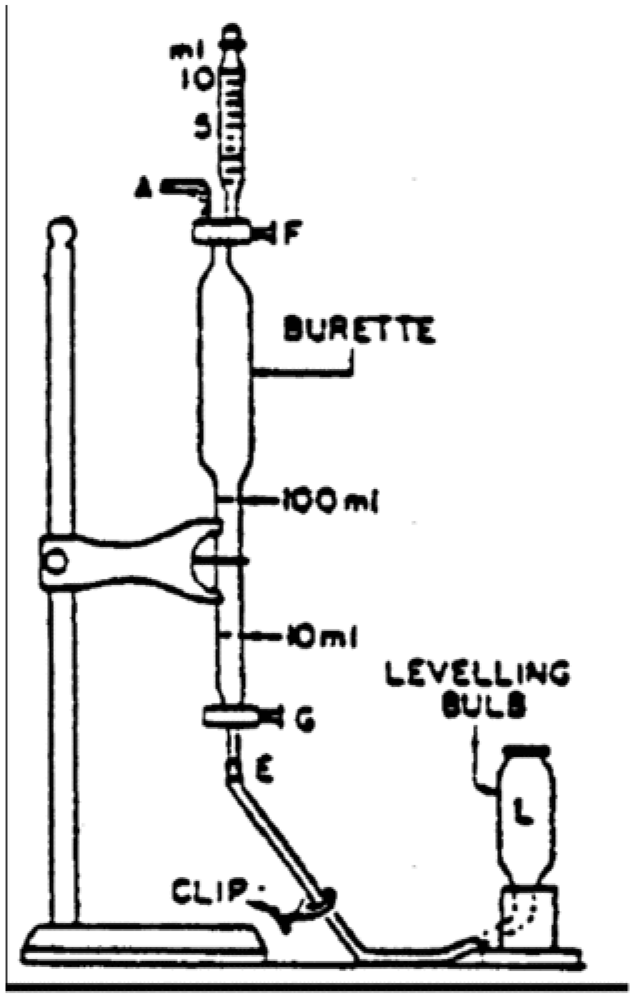


Figure 1. Tutwiler burette (lettered items mentioned in text).

**§60.5410b How do I demonstrate initial compliance with the standards for each of my affected facilities?**

You must determine initial compliance with the standards for each affected facility using the requirements of paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on the date specified in §60.5370b and ends no later than 1 year after that date. The initial compliance period may be less than 1 full year.

(a) *Well completion standards for well affected facilities.* To achieve initial compliance with the GHG and VOC standards for each well completion operation conducted at your well affected facility as required by §60.5375b, you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in §60.5420b(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420b(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420b(c)(1)(i) through (iv) and (vii), as applicable, for each well completion operation conducted. If you meet the exemption at §60.5375b(g) for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420b(c)(1)(i) through (iv) and must maintain the record in §60.5420b(c)(1)(vi). If you meet the exemption at §60.5375b(h) for a well modified in accordance with §60.5365b(a)(1)(ii) (*i.e.*, an existing well is hydraulically refractured), you do not need to maintain the records in §60.5420b(c)(1)(i) through (iv) and must maintain the record in §60.5420b(c)(1)(viii).

(4) For each well completion affected facility subject to both §60.5375b(a)(1) and (2), as an alternative to retaining the records specified in §60.5420b(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420b(c)(1)(v).

(b) *Gas well liquids unloading standards for well affected facility.* To demonstrate initial compliance with the GHG and VOC standards for each gas well liquids unloading operation conducted at your well affected facility as required by §60.5376b, you must comply with paragraphs (b)(1) through (3) of this section, as applicable.

(1) You must submit the initial annual report for your well affected facility as required in §60.5420b(b)(1) and (3).

(2) If you comply by meeting the zero methane and VOC emissions standard of §60.5376b(b), you must maintain the records specified in §60.5420b(c)(2)(i).

(3) If you comply by meeting the exception to the zero emissions standard of §60.5376b(c), you must comply with paragraphs (b)(3)(i) through (iii) of this section.

(i) Provide written justification for the need for each exception, including supporting documentation as specified in §60.5420b(b)(3)(ii)(B).

(ii) Employ best management practices to minimize venting of methane and VOC emissions as specified in §60.5376b(d) for each gas well liquids unloading operation.

(iii) Maintain the records specified in §60.5420b(c)(2)(ii).

(c) *Oil well with associated gas standards for well affected facility.* To demonstrate initial compliance with the GHG and VOC standards for each oil well with associated gas at your well affected facility as required by §60.5377b, you must comply with paragraphs (c)(1) through (3) of this section.

(1) If you comply with the requirements of §60.5377b(a), you must maintain the records specified in §60.5420b(c)(3)(i).

(2) If you comply with §60.5377b(b), you must comply with paragraphs (c)(2)(A) through (H) of this section.

(A) Document the technical or safety reasons why it is infeasible to route recovered associated gas into a gas gathering flow line or collection system to a sales line, use it as an onsite fuel source, use it for another useful purpose that a purchased fuel or raw material would serve, or inject it into another well for enhanced oil recovery and submit this documentation in the initial annual report.

(B) Submit the certification as required by §60.5420b(b)(4)(ii)(A).

(C) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b.

(D) Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture the associated gas and route the captured associated gas to a control device that meets the conditions specified in §60.5412b. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(E) Conduct an initial performance test as required in §60.5413b within 180 days after initial startup or by **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of §60.5415b(c).

(F) Conduct the initial inspections required in §60.5416b(a) and (b).

(G) Install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(H) Maintain the records specified in §60.5420b(c)(3)(ii) and (c)(8) and (c)(10) through (13), as applicable.

(3) You must submit the initial annual report for your oil well with associated gas at a well affected facility as required in §60.5420b(b)(1) and (4) and (b)(11) through (13), as applicable.

(d) *Centrifugal compressor affected facility.* To demonstrate initial compliance with the GHG and VOC standards for your centrifugal compressor affected facility that uses a wet seal as required by §60.5380b, you must comply with paragraphs (d)(1) through (5) and paragraphs (d)(7) and (8) of this section. To demonstrate initial compliance with the GHG and VOC standards for your centrifugal compressor affected facility that is a dry seal centrifugal compressor or self-contained wet seal centrifugal compressor as required by §60.5380b, you must comply with paragraphs (d)(6) through (8) of this section.

(1) You must reduce methane and VOC emissions by 95.0 percent or greater according to §60.5380b(a)(1) and (2) and as demonstrated by the requirements of §60.5413b, or you must route emissions to a process according to §60.5380b(a)(3).

(2) If you use a control device to reduce emissions to comply with §60.5380b(a)(1) and (2), you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411b(b) that is connected through a closed vent system that meets the requirements of §60.5411b(a) and (c) and is routed to a control device that meets the conditions specified in §60.5412b(a), (b) and (c). If you comply with §60.5380b(a)(3) by routing the closed vent system to a process as an alternative to routing the closed vent system to a control device, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411b(b), and route captured vapors through a closed vent system that meets the requirements of §60.5411b(a) and (c).

(3) If you use a control device to comply with §60.5380b(a)(1) and (2), you must conduct an initial performance test as required in §60.5413b within 180 days after initial startup or by **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of §60.5415b(d).

(4) If you use a control device to comply with §60.5380b(a)(1) and (2) or comply with §60.5380b(a)(3) by routing to a process, you must conduct the initial inspections required in §60.5416b(a) and (b).

(5) If you use a control device to comply with §60.5380b(a)(1) and (2), you must install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(6) You must maintain the volumetric flow rate below 3 scfm for your dry seal compressor or self-contained wet seal centrifugal compressor and you must conduct your initial annual volumetric measurement as required by §60.5380b(a)(4)(ii).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420b(b)(1) and (5) and (b)(11) through (b)(13), as applicable.

(8) You must maintain the records as specified in §60.5420b(c)(4) and (c)(8) through (13), as applicable.

(e) *Reciprocating compressor affected facility*. To demonstrate initial compliance with the GHG and VOC standards for each reciprocating compressor affected facility as required by §60.5385b, you must comply with paragraphs (e)(1) through (4) of this section.

(1) If you comply with §60.5385b(a) by maintaining volumetric flow rate below 2 scfm, you must maintain volumetric flow rate below 2 scfm and you must conduct your initial annual volumetric flow rate measurement as required by §60.5385b(a)(1).

(2) If you comply with §60.5385b(a) by collecting the methane and VOC emissions from your reciprocating compressor rod packing using a rod packing emissions collection system as required by §60.5385b(a)(3), you must equip the reciprocating compressor with a rod packing emissions collection system that is operated to route emissions to a process through a closed vent

system that meets the requirements of §60.5411b(a) and (c) and you must conduct the initial inspections required in §60.5416b(a) and (b).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420b(b)(1), (6), and (11), as applicable.

(4) You must maintain the records as specified in §60.5420b(c)(5), (8), (10), and (12) as applicable.

(f) *Pneumatic controller affected facility*. To demonstrate initial compliance with GHG and VOC emission standards for your pneumatic controller affected facility as required by the non-venting requirements of §60.5390b(a), you must comply with paragraphs (f)(1), (f)(3) and (f)(4) of this section. To demonstrate initial compliance with the GHG and VOC standards for pneumatic controller affected facilities complying with the requirements of §60.5390b(b), you must comply with paragraphs (f)(2) through (f)(4) of this section.

(1) You must demonstrate that your pneumatic controller affected facility does not vent any VOC or methane to the atmosphere by meeting the requirements of paragraphs (f)(1)(i) or (f)(1)(ii) of this section.

(i) If you comply by routing the emissions to a process, you must demonstrate that the pneumatic controller affected facility emissions are routed to a process through a closed vent system as specified in paragraphs (f)(1)(i)(A) through (C) of this section.

(A) Comply with the initial closed vent system requirements of §60.5411b(a) and (c).

(B) Comply with the initial closed vent system inspection and monitoring requirements of §60.5416b(a) and (b).

(C) Maintain the records as required by §60.5420b(c)(8), (c)(10) and (c)(12) and submit the reports as required by §60.5420b(b)(7)(ii)(A).

(ii) If you comply by using a self-contained natural gas-driven pneumatic controller, you must demonstrate that the self-contained natural gas-driven pneumatic controller meets the design and operation requirements specified in paragraph (f)(1)(ii)(A) and (B) for each self-contained natural gas-driven pneumatic controller.

(A) Conduct an initial no identifiable emissions inspection required by §60.5416b(b).

(B) Maintain records of the initial no identifiable emissions inspection that demonstrate that each self-contained natural gas-driven pneumatic controller is designed and operated with no identifiable emissions as required by §60.5420b(c)(6)(ii)(B) and submit the reports as required by §60.5420b(b)(7)(ii)(B).

(2) For each pneumatic controller affected facility located at a site in Alaska that does not have access to electrical power, you must demonstrate initial compliance with §60.5490b(b)(1) and (2) or with §60.5490b(b)(3), as an alternative to complying with paragraph §60.5490b(a) by meeting the requirements specified in (f)(2)(i) through (v) of this section for each pneumatic controller, as applicable.

(i) For each pneumatic controller in the pneumatic controller affected facility operating with a bleed rate of less than or equal to 6 scfh, you must maintain records in accordance with §60.5420b(c)(6)(iii)(A) that demonstrate the pneumatic controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(ii) For each pneumatic controller in the pneumatic controller affected facility operating with a bleed rate greater than 6 scfh, you must maintain records that demonstrate that a controller with a higher bleed rate than 6 scfh is required based on a specific functional need for that controller as specified in §60.5420b(c)(6)(iii)(B).

(iii) For each pneumatic controller in the pneumatic controller affected facility described by paragraph (f)(2)(i) or (ii) of this section, you must submit the information specified in §60.5420b(b)(7)(iii)(A) in the initial annual report after the controller is installed.

(iv) For each intermittent vent pneumatic controller in the pneumatic controller affected facility you must demonstrate that each intermittent vent controller does not vent to the atmosphere during idle periods by conducting initial monitoring in accordance with §60.5390b(b)(2)(ii), record the results in accordance with §60.5420b(c)(6)(iv), and submit reports in accordance with §60.5420b(b)(7)(iii)(B). You also must follow the requirements of paragraph (f)(2)(iv)(A) and (B), for each instance where initial monitoring identifies emissions to the atmosphere from each intermittent vent controller during idle periods, as applicable.

(A) You must record the deviation of the standard in accordance with the requirements in §60.5420b(c)(6)(iv) and report it in your initial annual report in accordance with §60.5420b(b)(7)(iii)(B).

(B) You must record and report the corrective action taken when emissions are detected during initial monitoring and the monitoring re-survey results after corrective action of the intermittent vent pneumatic controller is completed to verify/demonstrate that it is not venting emissions during idle periods in accordance with §60.5420b(c)(6)(iv) and (b)(7)(iii)(B), respectively.

(v) For each pneumatic controller affected facility that complies by reducing methane and VOC emissions from all controllers in the pneumatic controller affected facility by 95.0 percent in accordance with §60.5490b(b)(3), you must comply with paragraphs (b)(2)(v)(A) through (F) of this section.

(A) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b.

(B) Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture the emissions from all pneumatic controllers in the pneumatic controller affected facility and route all emissions to a control device that meets the conditions specified in §60.5412b.

(C) Conduct an initial performance test as required in §60.5413b within 180 days after initial startup or by **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e) and you must comply with the continuous compliance requirements of §60.5415b(h).

(D) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in §60.5416b(a) and (b).

(E) Install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(F) Maintain the records as required by §60.5420b(c)(8) and (c)(10) through (c)(13) and submit the reports as required by §60.5420b(b)(11) through (13).

(3) You must submit the initial annual report for your pneumatic controller affected facility as required in §60.5420b(b)(1) and (7).

(4) You must maintain the records as specified in §60.5420b(c)(6).

(g) *Pneumatic pump affected facility.* To demonstrate initial compliance with the GHG and VOC standards for your pneumatic pump affected facility as required by §60.5393b, you comply with paragraphs (g)(1) through (6), as applicable.

(1) You must submit the identification of all your pneumatic pumps that are not powered by natural gas in your initial annual report as required by §60.5420b(b)(10)(i).

(2) You must meet the requirements of §60.5393b(d), to collect and route vapors to a process through a closed vent system, for all the natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power, as specified in paragraphs (g)(2)(i) through (iii) of this section.

(i) Comply with the initial closed vent system requirements of §60.5411b(a) and (c).

(ii) Comply with the initial closed vent system inspection and monitoring requirements of §60.5416b(a) and (b).

(iii) Maintain the records as required by §60.5420b(c)(8), (c)(10) and (c)(12) and submit the reports as required by §60.5420b(b)(10)(ii) and (b)(11)(i) through (iv).

(3) You must meet the requirements of §60.5393b(f), to collect and route vapors to a control device through a closed vent system that reduces emissions by 95.0 percent for all of your natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power, as specified in paragraphs (g)(3)(i) through (vi) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b.

(ii) Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture all emissions from all pneumatic pumps in the pneumatic pump affected facility and route all emissions to a control device that meets the conditions specified in §60.5412b.

(iii) Conduct an initial performance test as required in §60.5413b within 180 days after initial startup or by **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE**

**IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of §60.5415b(e).

(iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in §60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(vi) Maintain the records as required by §60.5420b(c)(8) and (c)(10) through (c)(13) and submit the reports as required by §60.5420b(b)(10)(iii) and (b)(11) through (13).

(4) Submit the certification in paragraphs (g)(5)(i) through (iii) of this section, as applicable.

(i) The certification as required by §60.5420b(b)(10)(iv) for each pneumatic pump that it is technically infeasible to use a solar powered pneumatic pump or to use a generator to power compressed air.

(ii) The certification as required by §60.5420b(b)(10)(v) where it is technically infeasible to capture and route all emissions to an existing control device.

(iii) The certification as required by §60.5420b(b)(10)(vi) that there is no control device or process available on site.

(iv) The certification as required by §60.5420b(b)(10)(vii) that there is a control device on site, but it does not achieve a 95.0 percent reduction.

(5) You must submit the initial annual report for your pneumatic pump affected facility as specified in §60.5420b(b)(1) and (10).

(6) You must maintain the records for your pneumatic pump affected facility as specified in §60.5420b(c)(15).

(h) *Process unit equipment affected facility*. To achieve initial compliance with the GHG and VOC standards for process unit equipment affected facilities as required by §60.5400b, you must comply with paragraphs (h)(1) through (4) and (h)(11) through (16) of this section, unless you meet and comply with the exception in §60.5402b(b), (e), or (f) or meet the exemption in §60.5402b(c). If you comply with the GHG and VOC standards for process unit equipment affected facilities using the alternative standards in §60.5401b, you must comply with paragraphs (h)(5) through (16) of this section, unless you meet the exemption in §60.5402b(b) or (c) or the exception in §60.5402b(e) or (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service and connector in gas/vapor or light liquid service as required by §60.5400b(b).

(2) You must conduct monitoring as required by §60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by §60.5400b(d) for each pressure relief device in gas/vapor service.

(4) You must comply with the equipment requirements for each open-ended valve or line as required by §60.5400b(e).

(5) You must conduct monitoring for each pump in light liquid service as required by §60.5401b(b).

(6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by §60.5401b(c).

(7) You must comply with the equipment requirements for each open-ended valve or line as required by §60.5401b(d).

(8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by §60.5401b(f).

(9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by §60.5401b(g).

(10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by §60.5401b(h).

(11) For each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or a control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or a control device, you must meet the requirements of paragraph (h)(11)(i) through (vi) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b or route to a process.

(ii) Install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture all emissions from each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir, each pump which captures and transports leakage from the seal or seals, or each pressure relief device which captures and transports leakage through the pressure relief device and route all emissions to a process or to a control device that meets the conditions specified in §60.5412b.

(iii) If routing to a control device, conduct an initial performance test as required in §60.5413b within 180 days after initial startup or by **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of §60.5415b(e).

(iv) Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in §60.5416b(a) and (b).

(v) Install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(vi) Maintain the records as required by §60.5420b(c)(8) and (c)(10) through (c)(13), as applicable and submit the reports as required by §60.5420b(b)(11) through (13), as applicable.

(12) You must tag and repair each identified leak as required in §60.5400b(h) or §60.5400b(i), as applicable.

(13) You must submit the notice required by §60.5420b(a)(1).

(14) You must submit the initial semiannual report and subsequent semiannual report as required by §60.5422b.

(15) You must maintain the records specified by §60.5421b.

(i) *Sweetening unit affected facility.* To achieve initial compliance with the $SO_2$ standard for your sweetening unit affected facility as required by §60.5405b, you must comply with paragraphs (i)(1) through (13) of this section.

(1) You must conduct an initial performance test as required by §60.8 and according to the requirements of §60.5406b.

(2) You must determine the minimum required initial reduction efficiency of $SO_2$ emissions ($Z_i$) as required by §60.5406b(b).

(3) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology using the procedures in §60.5406b(c)(1) through (4).

(4) You must demonstrate compliance with the standard as required by §60.5405b(a) by comparing the minimum required $SO_2$ emission reduction efficiency ($Z_i$) to the emission reduction efficiency achieved by the sulfur recovery technology (R), where R must be greater than or equal to $Z_i$.

(5) You must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the accumulation of sulfur product, the $H_2S$ concentration, the average acid gas flow rate, and the sulfur feed rate in accordance with §60.5407b(a).

(6) You must determine the required $SO_2$ emissions reduction efficiency each 24-hour period in accordance with §60.5407b(a), (d), and (e), as applicable.

(7) You must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors in accordance with §60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by an incineration device.

(8) You must continuously operate the incineration device if you use an oxidation control system, or a reduction control system followed by an incineration device.

(9) You must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds in accordance with §60.5407b(c), (f), and (g), if you use a reduction control system not followed by an incineration device.

(10) You must submit the notification required by §60.5420b(a)(1).

(11) You must submit the initial annual report required by §60.5423b(b).

(12) You must submit the annual excess emissions reports required by §60.5423b(d), if applicable.

(13) You must maintain the records required by §60.5423b(a), (e) and (f), as applicable.

(j) *Storage vessel affected facility.* To achieve initial compliance with the GHG and VOC standards for each storage vessel affected facility as required by §60.5395b, you must comply with paragraphs (j)(1) through (9) of this section. To achieve initial compliance with the GHG and VOC standards for each storage vessel affected facility that complies by using a floating roof in accordance with §60.5395b(b)(2), you must comply with paragraph (j)(10) of this section.

(1) You must determine the potential for methane and VOC emissions as specified in §60.5365b(e)(2).

(2) You must reduce methane and VOC emissions by 95.0 percent or greater according to §60.5395b(a) and as demonstrated by the requirements of §60.5413b.

(3) If you use a control device to reduce emissions, you must equip each storage vessel in the storage vessel affected facility with a cover that meets the requirements of §60.5411b(b), install a closed vent system that meets the requirements of §60.5411b(a) and (c) to capture all emissions from the storage vessel affected facility, and route all emissions to a control device that meets the conditions specified in §60.5412b.

(4) You must conduct an initial performance test as required in §60.5413b within 180 days after initial startup or within 180 days of **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, whichever is later, or install a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), and you must comply with the continuous compliance requirements of §60.5415b(i).

(5) You must conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in §60.5416b(a) and (b).

(6) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) through (g), as applicable.

(7) You must maintain the records as required by §60.5420b(c)(8) through (c)(13), as applicable and submit the reports as required by §60.5420b(b)(11) through (13), as applicable.

(8) You must submit the initial annual report for your storage vessel affected facility required by §60.5420b(b)(1) and (8).

(9) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420b(c)(7) for each storage vessel affected facility.

(10) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112b(d)(a)(1) or (2) in accordance with §60.5395b(b)(2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(k) *Fugitive emission components affected facility.* To achieve initial compliance with the GHG and VOC standards for fugitive emissions components affected facilities as required by §60.5397b, you must comply with paragraphs (k)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in §60.5397b(b), (c), and (d).

(2) You must conduct an initial monitoring survey as required in §60.5397b(e) and (f).

(3) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397b(h).

(4) You must submit the initial annual report for each fugitive emissions components affected facility as required in §60.5420b(b)(1) and (9).

(5) You must maintain the records specified in §60.5420b(c)(14).

**§60.5411b What additional requirements must I meet to determine initial compliance for my covers and closed vent systems?**

For each closed vent system or cover at your well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Closed vent system requirements*.

(1) Reciprocating compressor rod packing, pneumatic controllers, and pneumatic pumps. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process.

(2) Oil wells with associated gas, centrifugal compressors, pneumatic controllers in Alaska, pneumatic pumps, storage vessels, and process unit equipment. You must design the closed vent system to capture and route all gases, vapors, and fumes to a process or a control device that meets the requirements specified in §60.5412b(a) through (d).

(3) You must design and operate the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.

(4) Bypass devices. You must meet the requirements specified in paragraphs (a)(4)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(4)(ii) of this section, you must comply with either paragraph (a)(4)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device. The flow indicator must be capable of taking periodic readings as specified in §60.5416b(a)(4)(i) and sound an alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process, and sent to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420b(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(4)(i) of this section.

(b) *Cover requirements for storage vessels and centrifugal compressors.*

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or centrifugal compressor wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) *Design requirements.*

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility. The assessment must be certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (c)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of subpart OOOOb of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

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

**§60.5412b What additional requirements must I meet for determining initial compliance of my control devices?**

You must meet the requirements of paragraphs (a) and (b) of this section for each control device used to comply with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.

(a) Each control device used to meet the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under §60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).

(1) Each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with paragraph (a)(1)(i) of this section, meet one of the operating limits specified in paragraphs (a)(1)(ii) through (v) of this section, and except for boilers and process heaters meeting the requirements of paragraph (a)(1)(iii) of this section and catalytic vapor incinerators meeting the

requirements of paragraph (a)(1)(v) of this section, meet the operating limit specified in paragraph (a)(1)(vi) through (viii) of this section.

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

(ii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413b(b), that combustion zone temperature is an indicator of destruction efficiency.

(iii) You must introduce the vent stream into the flame zone of a boiler or process heater, and you must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

(iv) For enclosed combustion devices for which, during the performance test conducted under §60.5413b(b), the combustion zone temperature is not an indicator of destruction efficiency, you must maintain the net heating value (NHV) of the gas sent to the combustor above the applicable limits specified in paragraphs (a)(1)(iv)(A) through (C) of this section.

(A) For enclosed combustion devices that do not use assist gas or pressure-assisted burner tips to promote mixing at the burner tip, 200 British thermal units per standard cubic feet (Btu/scf).

(B) For enclosed combustion devices that use assist gas to promote mixing at the burner tip, 300 Btu/scf.

(C) For enclosed combustion devices that use pressure-assisted burner tips to promote mixing at the burner tip, 800 Btu/scf.

(v) For an enclosed combustion device which is a catalytic vapor incinerator, you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with §60.5417b(f) and as determined in your performance test conducted in accordance with §60.5413b(b).

(vi) You must operate each enclosed combustion control device at or below the maximum inlet gas flow rate established in accordance with §60.5417b(f) and as determined in your performance test conducted in accordance with §60.5413b(b). You must operate the combustion control device at or above the minimum inlet gas flow rate established in accordance with §60.5417b(f).

(vii) You must install and operate a continuous burning pilot flame.

(viii) You must operate the enclosed combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test using section 11 of Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair, and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413b(b). As an alternative to the performance testing requirements of §60.5413b(b), you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413b(c). For a condenser, you also must calculate the daily average condenser outlet temperature in accordance with §60.5417b(e), and you must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature and the condenser performance curve established in accordance with §60.5417b(f)(2). You must determine the average TOC emission reduction in accordance with §60.5415b(f)(1)(ix)(D). For a carbon adsorption system, you also must comply with paragraph (c) of this section.

(3) Each flare must be designed and operated according to the requirements of §60.18(b) as specified in paragraphs (a)(3)(i) through (iv) of this section.

(i) You must use Method 18 of appendix A-6 of this part to determine the NHV of the vent gas meets the requirements in §60.18(c)(3)(ii). For pressure-assisted flares, in lieu of the heating value limits in §60.18(c)(3)(ii), the NHV of the gas being combusted must be 800 Btu/scf or greater.

(ii) For flares other than pressure-assisted flares, you must determine the maximum flow rate of vent gas to the control system based on the design considerations of the affected facilities to demonstrate compliance with the flare tip velocity limits in §60.18(b). The maximum flare tip velocity limits do not apply for pressure-assisted flares.

(iii) You must operate the flare with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. You must conduct the compliance determination with the visible emission limits using Method 22 of appendix A-7 of this part.

(iv) You must install and operate a continuous burning pilot flame.

(b) You must operate each control device installed on your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417b(a) through (g), you must demonstrate compliance according to the requirements of §60.5415b(f), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must comply with the requirements of paragraph (c)(1) of this section. If the carbon adsorption system is a regenerative-type carbon adsorption system, you also must comply with the requirements of paragraph (c)(2) of this section.

(1) You must manage the carbon in accordance with the requirements specified in paragraphs (c)(1)(A) and (B) of this section.

(A) Following the initial startup of the control device, you must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413b(c)(2) or (3). You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420b(c)(10) and (12).

(B) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(1)(B)(*1*) through (*6*) of this section.

(*1*) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(*2*) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emissions control in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(*3*) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(*4*) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE, and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(*5*) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(*6*) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(2) You must comply with the requirements of paragraph (c)(2)(i) through (iii) of this section for each regenerative-type carbon adsorption system.

(i) You must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle to demonstrate compliance with the total regeneration stream flow established in accordance with §60.5413b(c)(2).

(ii) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion, if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(iii) You must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. You must maintain the average carbon bed temperature above the temperature limit in established accordance with §60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in in accordance with §60.5413b(c)(2) after the regeneration cycle.

**§60.5413b What are the performance testing procedures for control devices?**

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412b(a)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct initial and periodic performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (6) of this section. You are exempt from the requirements to conduct an initial performance test if you use a control device described in paragraph (a)(7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions and using Method 18 of appendix A-6 of this part to determine net heating value of the vent gas.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420b(b)(12) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420b(b)(12) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A control device for which performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412b(a)(1)(i) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (4) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412b(a)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(4) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1b of appendix A-1 of this part, as appropriate, to select the sampling sites. Any references to particulate mentioned in Methods 1 and 1b do not apply to this section. Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(2) You must determine the gas volumetric flow rate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412b(a)(1)(i) or (a)(2), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$E_i = K_2 C_i M_p Q_i$

$E_o = K_2 C_o M_p Q_o$

Where:

$E_i$, $E_o$ = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

$K_2$ = Constant, $2.494 \times 10^{-6}$ (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

$C_i$, $C_o$ = Concentration of TOC, as propane, of the gas stream as measured by Method 25A of appendix A-7 of this part at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

$M_p$ = Molecular weight of propane, 44.1 gram/gram-mole.

$Q_i$, $Q_o$ = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

$R_{cd}$ = Control efficiency of control device, percent.

$E_i$, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

$E_o$ = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must conduct performance tests according to the schedule specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420b(b)(12).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except for a control device whose model is tested under, and meets the criteria of paragraph (d) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).

(c) *Control device design analysis to meet the requirements of §60.5412b(a)(2).*

(1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance

with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph (d) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10 to 15-minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10 to 15-minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10 to 15-minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A-1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a fused silica-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(B) Hydrogen ($H_2$), carbon monoxide (CO), carbon dioxide ($CO_2$), nitrogen ($N_2$), oxygen ($O_2$) using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in §60.17).

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the Method 3C tests and Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A-7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0 to 10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0 to 30 ppmvw (as propane) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—“EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent $CO_2$, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

$C_{meas}$ = The measured concentration of the pollutant.

$CO_{2meas}$ = The measured concentration of the $CO_2$ diluent.

3 = The corrected reference concentration of $CO_2$ diluent.

$C_{corr}$ = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent $CO_2$.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent $CO_2$.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a minimum inlet gas flow rate above which each control device model must be operated to achieve the criteria in paragraph (d)(11)(iii) of this section. The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The minimum and maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with §60.5420b(b)(13). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI to the OAQPS CBI office. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov and should include clear CBI markings and be flagged to the attention of the Leader, Measurement Technology Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If you cannot transmit the file electronically, you may send CBI information

through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Group Leader, Fuels and Incineration Group. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Continuous pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Initial and continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (9) of this section, maintaining the records specified in §60.5420b(c)(11)(i) and submitting the report specified in §§60.5420b(b)(11)(v) and (b)(13).

(1) The inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 of this part must be performed at least once every

calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(9) Install and operate the continuous parameter monitoring systems in accordance with §60.5417b(a) and (c) through (g).

**§60.5415b How do I demonstrate continuous compliance with the standards for each of my affected facilities?**

(a) *Well completion standards for well affected facility.* For each well completion operation at your well affected facility, you must demonstrate continuous compliance with the requirements of §60.5375b by submitting the annual report required by §60.5420b(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420b(c)(1).

(b) *Gas well liquids unloading standards for well affected facility.* For each well liquids unloading operation at your well affected facility, you must demonstrate continuous compliance with the requirements of §60.5376b by submitting the annual report information specified in §60.5420b(b)(1) and (3) and maintaining the records for each well liquids unloading event specified in §60.5420b(c)(2).

(c) *Oil well with associated gas standards for well affected facility.* For each oil well with associated gas at your well affected facility, you must demonstrate continuous compliance with the requirements of §60.5377b by submitting the reports required by §60.5420b(b)(1) and (4) and maintaining the records specified in §60.5420b(c)(3). For each oil well with associated gas at your well affected facility that complies with the requirements of §60.5377b(b), you also must comply with the requirements specified in paragraph (f) of this section and maintain the records in §60.5420b(c)(8), (10) and (12).

(d) *Centrifugal compressor affected facility.* For each wet seal centrifugal compressor affected facility complying with §60.5380b(a)(1) and (2), or with §60.5380b(a)(3)(i) by routing emissions to a control device or to a process, you must demonstrate continuous compliance according to paragraph (d)(1) and paragraphs (d)(3) and (4) of this section. For each dry seal centrifugal compressor and each self-contained wet seal centrifugal compressor complying with the requirements in §60.5380b(a)(4) and (5), you must demonstrate continuous compliance according to paragraphs (d)(2) through (4) of this section.

(1) For each wet seal centrifugal compressor affected facility complying by routing emissions to a control device or to a process, you must operate the wet seal emissions collection system to route emissions to a control device or a process through a closed vent system and continuously comply with the closed vent requirements of §60.5416b(a) and (b). If you comply with §60.5380b(a)(2) by using a control device, you also must comply with the requirements in paragraph (f) of this section.

(2) You must maintain volumetric flow rate below 3 scfm and you must conduct the required volumetric flow rate measurement of your dry seal centrifugal compressor or self-contained wet seal centrifugal compressor in accordance with §60.5380b(a)(5) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the 3 scfm volumetric flow rate.

(3) You must submit the annual reports as required in §60.5420b(b)(1) and (5) and (11)(i) through (iv), as applicable.

(4) You must maintain records as required in §60.5420b(c)(4) and (8) through (10) and (12), as applicable.

(e) *Pneumatic pump affected facility.* To demonstrate continuous compliance with the GHG and VOC standards for your pneumatic pump affected facility as required by §60.5393b, you must comply with paragraphs (e)(1) through (7), as applicable.

(1) You must submit the identification of each of your pneumatic pumps that are not powered by natural gas in your annual report as required by §60.5420b(b)(10)(i).

(2) You must meet the requirements of §60.5393b(d), to collect and route vapors to a process through a closed vent system for all the natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power, as specified in paragraphs (e)(2)(i) through (ii) of this section.

(i) Comply with the closed vent system inspection and monitoring requirements of §60.5416b(a) and (b).

(ii) Maintain the records as required by §60.5420b(c)(8), (c)(10) and (c)(12) and submit the reports as required by §60.5420b(b)(10)(ii) and (b)(11)(i) through (iv).

(3) You must meet the requirements of §60.5393b(f), to collect and route vapors to a control device through a closed vent system that reduces emissions by 95.0 percent for all natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power, as specified in paragraphs (e)(3)(i) through (iv) of this section.

(i) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b.

(ii) Conduct inspections of the closed vent system and operate bypasses, as applicable, as required in §60.5416b(a) and (b).

(iii) Comply with the requirements specified in paragraph (f) of this section.

(iv) Maintain the records as required by §60.5420b(c)(8), (c)(10) and (c)(12) of this section and submit the reports as required by §60.5420b(b)(10)(iii) of this section.

(4) Submit the information specified in paragraph §60.5420b(b)(10)(viii) of this section in your annual report, as applicable, after the method of compliance for a pneumatic pump has changed.

(5) You must submit the requisite certifications for all pneumatic pumps included in the pneumatic pump affected facility where you are unable to meet the requirements under §60.5393b(d) or (g)(3) or where you meet the requirements of §60.5393b(g)(1) or (2) as required by §60.5420b(b)(10)(v) and (vi).

(6) You must submit the annual reports for your pneumatic pump affected facility as required in §60.5420b(b)(1) and (10).

(7) You must maintain the records for your pneumatic pump affected facility as specified in §60.5420b(c)(15).

(f) *Additional continuous compliance requirements for well, centrifugal compressor, pneumatic controllers in Alaska, storage vessel, process unit equipment, or pneumatic pump affected facilities.* For each oil well with associated gas at your well affected facility, each centrifugal compressor affected facility, each pneumatic controller affected facility in Alaska, each storage vessel affected facility, each process unit equipment affected facility, and each pneumatic pump affected facility referenced to this paragraph from either paragraph (c), (d)(1), (e)(3), (h)(2)(iv), (i) or (j) of this section, you must also install monitoring systems as specified in §60.5417b, demonstrate continuous compliance according to paragraph (f)(1) of this section, maintain the records in paragraph (f)(2) of this section, and comply with the reporting requirements specified in paragraph (f)(3) of this section.

(1) You must demonstrate continuous compliance with the control device performance requirements of §60.5412b(a) using the procedures specified in paragraphs (f)(1)(i) through (viii) of this section and conducting the monitoring as required by §60.5417b. If you use a condenser as the control device to achieve the requirements specified in §60.5412b(a)(2), you may demonstrate compliance according to paragraph (f)(1)(ix) of this section. You may switch

between compliance with paragraphs (f)(1)(i) through (viii) of this section and compliance with paragraph (f)(1)(ix) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site-specific maximum (or minimum) parameter value established according to the requirements of §60.5417b(f)(1). For flares, you must operate above the limits specified in paragraphs (f)(1)(vii)(B) of this section.

(ii) You must calculate the average of the applicable monitored parameter in accordance with §60.5417b(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the average of the monitoring parameter value calculated under paragraph (f)(1)(ii) of this section is either equal to or greater than the minimum parameter value or equal to or less than the maximum parameter value established under paragraph (f)(1)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413b(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413b(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417b(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements.

(vii) If you use an enclosed combustion control device to meet the requirements of §60.5412b(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413b(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with the applicable paragraphs (f)(1)(vii)(A) through (E) of this section.

(A) For each enclosed combustor which is not a catalytic vapor incinerator and each flare, you must comply with the requirements in paragraphs (f)(1)(vii)(A)(*1*) through (*4*) of this section.

*(1)* A pilot flame must be present at all times of operation.

(*2*) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22 of appendix A-7 of this part, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(*3*) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(*4*) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (f)(1)(vii)(D) of this section.

(B) For flares, you must comply with the requirements in paragraphs (f)(1)(vii)(B)(*1*) and (*2*) of this section.

(*1*) Maintain the NHV of the gas sent to the flare above the applicable limits specified in §60.18, unless you use a pressure-assisted flare. If you use a pressure assisted flare, maintain the NHV of gas sent to the flare above 800 Btu/scf; and

(*2*) Unless you use a pressure-assisted flare, maintain the flare tip velocity below the applicable limits in §60.18.

(C) For enclosed combustion devices for which, during the performance test conducted under §60.5413b(b), the combustion zone temperature is not an indicator of destruction efficiency, you must comply with the requirements in paragraphs (f)(1)(vii)(C)(*1*) and (*2*) of this section.

(*1*) Maintain the NHV of the gas sent to the combustor above the applicable limits specified in §60.5412b(a)(1)(iv); and

(*2*) Maintain the total gas flow to the combustor at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustor established in accordance with §60.5417b(f).

(D) For enclosed combustion devices for which, during the performance test conducted under §60.5413b(b), the combustion zone temperature is demonstrated to be an indicator of destruction efficiency, you must maintain the temperature at or above 760 °Celsius and you must maintain the total gas flow to the combustor at or above the minimum inlet gas flow rate and at or below the maximum inlet flow rate for the enclosed combustor established in accordance with §60.5417b(f).

(E) For catalytic vapor incinerators you must operate the catalytic vapor incinerator at or above the minimum temperature of the catalyst bed inlet and at or above the minimum temperature differential between the catalyst bed inlet and the catalyst bed outlet established in accordance with §60.5417b(f).

(viii) If you use a carbon adsorption system as the control device to meet the requirements of §60.5412b(a)(2), you must demonstrate compliance by the procedures in paragraphs (f)(1)(viii)(A) and (B) of this section, as applicable.

(A) If you use a regenerative-type carbon adsorption system, you must comply with the paragraphs (f)(1)(viii)(A)(*1*) through (*4*) of this section.

(*1*) You must maintain the average regenerative mass flow or volumetric flow to the carbon adsorber during each bed regeneration cycle above the limit established in in accordance with §60.5413b(c)(2).

(*2*) You must maintain the average carbon bed temperature above the temperature limit established in accordance with §60.5413b(c)(2) during the carbon bed steaming cycle and below the carbon bed temperature established in in accordance with §60.5413b(c)(2) after the regeneration cycle.

(*3*) You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your continuous parameter monitoring system is not equipped with a redundant flow sensor.

(*4*) You must replace all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413b(c)(2).

(B) If you use a nonregenerative-type carbon adsorption system, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413b(c)(3).

(ix) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412b(a)(2), you must demonstrate compliance using the procedures in paragraphs (f)(1)(ix)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417b(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417b(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (f)(1)(ix)(B) of this section and the condenser performance curve established under paragraph (f)(1)(ix)(A) of this section.

(D) Except as provided in paragraphs (f)(1)(ix)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(1)(ix)(C) of this section.

(*1*) After the compliance dates specified in §60.5370b(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370b(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (f)(1)(ix)(D) of this section is equal to or greater than 95.0 percent.

(2) You must maintain the records as specified in §60.5420b(c)(11) and (13).

(3) You must comply with the reporting requirements in §60.5420b(b)(11) through (13).

(g) *Reciprocating compressor affected facility*. For each reciprocating compressor affected facility complying with §60.5385b(a) through (c), you must demonstrate continuous compliance according to paragraphs (g)(1) and (g)(3) and (4) of this section. For each reciprocating compressor affected facility complying with §60.5385b(d), you must demonstrate continuous compliance according to paragraph (g)(4) through (6) of this section.

(1) You must maintain the volumetric flow rate at or below 2 scfm and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing in accordance with §60.5385b(b) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the 2 scfm volumetric flow rate.

(2) You must operate the rod packing emissions collection system to route emissions to a process through a closed vent system and continuously comply with the closed vent requirements of §60.5416b(a) and (b).

(3) You must submit the annual reports as required in §60.5420b(b)(1), (b)(6), and (b)(11)(i) through (iv), as applicable.

(4) You must maintain records as required in §60.5420b(c)(5), and (c)(8), (c)(10), and (c)(12), as applicable.

(h) *Pneumatic controller affected facility*. To demonstrate continuous compliance with GHG and VOC emission standards for your pneumatic controller affected facility as required by the non-venting requirements of §60.5390b(a), you must comply with paragraph (h)(1), (h)(3) and (h)(4) of this section. To demonstrate continuous compliance with the GHG and VOC standards for pneumatic controller affected facilities complying with the requirements of §60.5390b(b), you must comply with paragraphs (h)(2) through (h)(4) of this section.

(1) You must demonstrate that your pneumatic controller affected facility does not vent any VOC or methane to the atmosphere by meeting the requirements of paragraphs (h)(1)(i) or (h)(1)(ii) of this section.

(i) If you comply by routing the emissions to a process, you must demonstrate that the pneumatic controller affected facility emissions are routed to a process through a closed vent system as specified in paragraphs (h)(1)(i)(A) and (B) of this section.

(A) Comply with the closed vent system inspection and monitoring requirements of §60.5416b(a) and (b).

(B) Maintain the records as required by §60.5420b(c)(6)(ii)(A), (c)(8), (c)(10), and (c)(12) and submit the reports as required by §60.5420b(b)(7)(ii)(A) and (b)(11)(i) through (iv).

(ii) If you comply by using a self-contained natural gas-driven pneumatic controller, you must demonstrate that the self-contained natural gas-driven pneumatic controller meets the design and operation requirements specified in paragraph (h)(1)(ii)(A) and (B) for each self-contained natural gas-driven pneumatic controller.

(A) Conduct no identifiable emissions inspections required by §60.5416b(b).

(B) Maintain records of no identifiable emissions inspections that demonstrate that your self-contained natural gas-driven pneumatic controller is designed and operated with no identifiable emissions as required by §60.5420b(c)(6)(ii)(B) and submit the reports as required by §60.5420b(b)(7)(ii)(B).

(2) For each pneumatic controller affected facility located at a site in Alaska that does not have access to electrical power, you must demonstrate continuous compliance with either §60.5390b(b)(1) and (2) or with §60.5390b(b)(3), as an alternative to complying with paragraph

§60.5490b(a) by meeting the requirements specified in (f)(2)(i) through (v) of this section for each pneumatic controller, as applicable.

(i) For each pneumatic controller in the pneumatic controller affected facility operating with a bleed rate of less than or equal to 6 scfh, you must maintain records in accordance with §60.5420b(c)(6)(iii)(A) that demonstrate the pneumatic controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh,

(ii) For each pneumatic controller in the pneumatic controller affected facility operating with a bleed rate greater than 6 scfh, you must maintain records that demonstrate that a controller with a higher bleed rate than 6 scfh is required based on a specific functional need for that controller as specified in §60.5420b(c)(6)(iii)(B).

(iii) For each intermittent vent pneumatic controller in the pneumatic controller affected facility you must demonstrate that the intermittent vent controller does not vent to the atmosphere during idle periods by conducting continuous monitoring in accordance with §60.5390b(b)(2)(ii), record the results in accordance with §60.5420b(c)(6)(iv) and submit reports in accordance with §60.5420b(b)(7)(iii)(B). You also must follow the requirements of paragraph (h)(2)(iii)(A) and (B), for each instance where initial monitoring identifies emissions to the atmosphere from each intermittent vent controller during idle periods, as applicable.

(A) You must record the deviation of the standard in accordance with the requirements in §60.5420b(c)(6)(iv)(D) and report it in your annual report in accordance with §60.5420b(b)(7)(iii)(B).

(B) You must record and report the corrective action taken when emissions are detected during monitoring and the monitoring re-survey results after corrective action of the intermittent vent pneumatic controller is completed to verify and demonstrate that it is not venting emissions during idle periods in accordance with §60.5420b(c)(6)(iv) and (b)(7)(iii)(B), respectively.

(iv) For each pneumatic controller affected facility that complies by reducing methane and VOC emissions from all controllers in the pneumatic controller affected facility by 95.0 percent in accordance with §60.5490b(b)(3), you must comply with paragraphs (h)(2)(iv)(A) through (D) of this section.

(A) Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of §60.5413b.

(B) Conduct inspections of the closed vent system and operate bypasses, as applicable, as required in §60.5416b(a) and (b).

(C) Comply with the requirements specified in paragraph (f) of this section.

(D) Maintain the records as required by §60.5420b(c)(8) and (c)(10), and (c)(12), as applicable.

(v) Submit the information specified in paragraph (b)(7)(iii)(D) in your annual report, as applicable after the method of compliance for a pneumatic controller is changed.

(3) You must submit the annual report for your pneumatic controller as required in §60.5420b(b)(1) and (7).

(4) You must maintain the records as specified in §60.5420b(c)(6) for each pneumatic controller affected facility.

(i) *Storage vessel affected facility*. For each storage vessel affected facility, you must demonstrate continuous compliance with the requirements of §60.5395b according to paragraphs (i)(1) through (10) of this section, as applicable.

(1) For each storage vessel affected facility complying with the requirements of §60.5395b(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(5) and (i)(9) and (10) of this section.

(2) For each storage vessel affected facility complying with the requirements of §60.5395b(a)(3), you must demonstrate continuous compliance according to paragraphs (i)(2)(i), (ii) or (iii) of this section, as applicable, and (i)(9) and (10) of this section.

(i) You must maintain the uncontrolled actual VOC emissions at less than 4 tpy and the uncontrolled actual methane emissions at less than 14 tpy from the storage vessel affected facility.

(ii) You must comply with paragraph (i)(5) of this section, as soon as liquids from the well are routed to the storage vessel affected facility following fracturing or refracturing according to the requirements of §60.5395b(a)(3)(i).

(iii) You must comply with paragraph (i)(5) of this section within 30 days of the monthly determination according to the requirements of §60.5395b(a)(3)(ii), where the monthly emissions determination indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility.

(3) For each storage vessel affected facility or portion of a storage vessel affected facility removed from service, you must demonstrate compliance with the requirements of §60.5395b(c)(1), by complying with paragraphs (i)(6) and (7) and (i)(9) and (10) of this section.

(4) For each storage vessel affected or portion of a storage vessel affected facility returned to service, you must demonstrate compliance with the requirements of §60.5395b(c)(1) by complying with paragraphs (i)(8) through (10) of this section.

(5) For each storage vessel affected facility, you must comply with paragraphs (i)(5)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395b(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395b(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412b for each storage vessel affected facility using the procedure specified in paragraph (i)(5)(ii)(A) and (i)(5)(ii)(B) of this section. When routing emissions to a process, you must demonstrate continuous compliance as specified in paragraph (i)(5)(ii)(A).

(A) You must comply with §60.5416b for each cover and closed vent system.

(B) You must comply with the requirements specified in paragraph (f) of this section.

(6) You must completely empty and degas each storage vessel, such that each storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. For a portion of a storage vessel affected facility to be removed from service, you must completely empty and degas the storage vessel(s), such that the storage vessel(s) no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(7) You must disconnect the storage vessel(s) from the tank battery by isolating the storage vessel(s) from the tank battery such that the storage vessel(s) is no longer manifolded to the tank battery by liquid or vapor transfer.

(8) You must determine the affected facility status of a storage vessel returned to service as provided in §60.5365b(e)(6).

(9) You must submit the annual reports as required by §60.5420b(b)(1) and (8).

(10) You must maintain the records as required by §60.5420b(c)(7) through (10), and (12), as applicable.

(j) *Process unit equipment affected facility.* For each process unit equipment affected facility, you must demonstrate continuous compliance with the requirements of §60.5400b according to paragraphs (j)(1) through (4) and (11) through (16) of this section, unless you meet and comply with the exception in §60.5402b(b), (e), or (f) or meet the exemption in §60.5402b(c). Alternatively, if you comply with the GHG and VOC standards for process unit affected facilities using the standards in §60.5401b, you must comply with paragraphs (j)(5) through (16) of this section, unless you meet the exemption in §60.5402b(b) or (c) or the exception in §60.5402b(e) and (f).

(1) You must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by §60.5400b(b).

(2) You must conduct monitoring as required by §60.5400b(c) for each pump in light liquid service.

(3) You must conduct monitoring as required by §60.5400b(d) for each pressure relief device in gas/vapor service.

(4) You must comply with the equipment requirements for each open-ended valve or line as required by §60.5400b(e).

(5) You must conduct monitoring for each pump in light liquid service as required by §60.5401b(b).

(6) You must conduct monitoring for each pressure relief device in gas/vapor service as required by §60.5401b(c).

(7) You must comply with the equipment requirements for each open-ended valve or line as required by §60.5401b(d).

(8) You must conduct monitoring for each valve in gas/vapor or light liquid service as required by §60.5401b(f).

(9) You must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by §60.5401b(g).

(10) You must conduct monitoring for each connector in gas/vapor or light liquid service as required by §60.5401b(h).

(11) You must collect emissions and meet the closed vent system requirements as required by §60.5416b for each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or control device.

(12) You must meet the control device requirements of §60.5417b and comply with the requirements specified in paragraph (f) of this section.

(13) You must tag and repair each identified leak as required in §60.5400(h) or §60.5400b(i), as applicable.

(14) You must submit semiannual reports as required by §60.5422b.

(15) You must maintain the records specified by §60.5420b(c)(8), (c)(10), and (c)(12) as applicable and §60.5421b.

(k) *Sweetening unit affected facility*. For each sweetening unit affected facility, you must demonstrate continuous compliance with the requirements of §60.5405b(b) according to paragraphs (k)(1) through (10) of this section.

(1) You must determine the minimum required continuous reduction efficiency of $SO_2$ emissions ($Z_c$) as required by §60.5406b(b).

(2) You must determine the emission reduction efficiency (R) achieved by your sulfur reduction technology using the procedures in §60.5406b(c)(1) through (c)(4).

(3) You must demonstrate compliance with the standard at §60.5405b(b) by comparing the minimum required sulfur dioxide emission reduction efficiency ($Z_c$) to the emission reduction efficiency achieved by the sulfur recovery technology (R), where R must be greater than or equal to $Z_c$.

(4) You must calibrate, maintain, and operate monitoring devices or perform measurements to determine the accumulation of sulfur product, the $H_2S$ concentration, the average acid gas flow rate, and the sulfur feed rate in accordance with §60.5407b(a).

(5) You must determine the required $SO_2$ emissions reduction efficiency each 24-hour period in accordance with §60.5407b(a), §60.5407b(d), and §60.5407b(e), as applicable.

(6) You must calibrate, maintain, and operate monitoring devices and continuous emission monitors in accordance with §60.5407b(b), (f), and (g), if you use an oxidation control system or a reduction control system followed by an incineration device.

(7) You must continuously operate the incineration device, if you use an oxidation control system or a reduction control system followed by an incineration device.

(8) You must calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds in accordance with §60.5407b(c), (f), and (g), if you use a reduction control system not followed by an incineration device.

(9) You must submit the reports as required by §60.5423b(b) and (d).

(10) You must maintain the records as required by §60.5423b(a), (e) and (f), as applicable.

(l) For each fugitive emissions components affected facility, you must demonstrate continuous compliance with the requirements of §60.5397b(a) according to paragraphs (l)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in §60.5397b(e) and (g).

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

(3) You must submit annual reports for fugitive emissions components affected facilities as required in §60.5420b(b)(1) and (9).

(4) You must maintain records as specified in §60.5420b(c)(16).

**§60.5416b What are the initial and continuous cover and closed vent system inspection and monitoring requirements?**

For each closed vent system and cover at your well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected facilities, you must comply with the applicable requirements of paragraphs (a) and (b) of this section. Each self-contained natural gas pneumatic controller must comply with paragraph (b) of this section.

(a) *Inspections for closed vent systems, covers, and bypass devices.* If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section, except as provided in paragraphs (b)(6) and (7) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no identifiable emissions within the first 30 calendars days after startup of the affected facility routing emissions through the closed vent system. You must maintain records of the inspection results as specified in §60.5420b(c)(8) and the reports in §60.5420b(b)(11).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420b(c)(8).

(iii) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(1)(ii) of this section. You must maintain records of the results as specified §60.5420b(c)(8) and the reports as specified in§60.5420b(b)(11).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (v) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section within the first 30 calendars days after startup of the affected facility routing emissions through the closed vent system to demonstrate that the closed vent system operates with no identifiable emissions. You must maintain records of the inspection results as specified in §60.5420b(c)(8) and submit the reports as specified in§60.5420b(b)(11).

(ii) Conduct inspections according to the test methods, procedures, and frequencies specified in paragraph (b) of this section to demonstrate that the components or connections operate with no identifiable emissions. You must maintain records of the inspection results as specified in §60.5420b(c)(8) and submit the reports as specified in§60.5420b(b)(11).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420b(c)(8) and submit the reports as specified in§60.5420b(b)(11).

(iv) Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph (a)(2)(iii) of this section.

(v) You must maintain records of the results as specified §60.5420b(c)(8) and submit the reports as specified in§60.5420b(b)(11).

(3) For each cover, you must meet the requirements of paragraphs (a)(3)(i) through (v) of this section.

(i) Conduct the inspections specified in paragraphs (a)(3)(ii) through (iv) of this section to identify defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.*, fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) An initial inspection according to the test methods and procedures specified in paragraph (b) of this section, following installation of the cover to demonstrate that each cover operates with no identifiable emissions.

(iii) Monthly olfactory, visual and audible inspections, where subsequent monthly inspections must be separated by at least 14 calendar days.

(iv) Inspections according to the test methods, procedures, and schedules specified in paragraph (b) of this section to demonstrate that each cover operates with no identifiable emissions.

(v) You must maintain records of the inspection results as specified in §60.5420b(c)(9) and submit the reports as specified in§60.5420b(b)(11).

(4) For each bypass device, except as provided for in §60.5411b(a)(4)(ii), you must meet the requirements of paragraph (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device and to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420b(c)(10) and submit the reports as specified in §60.5420b(b)(11).

(b) *No identifiable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system and cover as specified in paragraph (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (8) of this section. You must meet the requirements of paragraphs (b)(1) through (b)(3) and (b)(8) of this section for each self-contained pneumatic controller at your pneumatic controller affected facility as specified at §60.5390b(a)(2).

(1) You must conduct initial and periodic optical gas imaging inspections as specified in paragraphs (b)(1)(A) through (C) of this section, as applicable.

(A) You must conduct inspection for no identifiable emissions from your closed vent systems and covers at your well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, or storage vessel affected facility, using the procedures for conducting optical gas imaging inspections in §60.5397b(c)(7). As an alternative you may conduct inspections in accordance with Method 21 of appendix A-7 of this part. Monitoring must be conducted at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in §60.5397b(g).

(B) For closed vent systems and covers located at onshore natural gas processing plants, optical gas imaging inspections for no identifiable emissions must be conducted initially and bimonthly in accordance with appendix K of this part. As an alternative you must conduct quarterly inspections for no identifiable emissions in accordance with Method 21 of appendix A-7 of this part.

(C) For your self-contained pneumatic controller, you must conduct initial and quarterly inspections for no identifiable emissions using optical gas imaging.

(2) Where optical gas imaging is used, the closed vent system and cover is determined to operate with no identifiable emissions if no emissions are imaged during the inspection.

(3) Where Method 21 is used for the inspection, the requirements of paragraphs (a)(3)(i) through (vii) apply.

(i) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of

Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(ii) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(iii) Calibration gases must be as specified in paragraphs (b)(3)(iii)(A) and (B) of this section.

(A) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(B) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(iv) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(v) Your detection instrument must meet the performance criteria specified in paragraphs (b)(3)(v)(A) and (B) of this section.

(A) Except as provided in paragraph (b)(3)(v)(B) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(B) If no instrument is available that will meet the performance criteria specified in paragraph (b)(3)(v)(A) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(3)(v)(A) of this section.

(vi) You must determine if a potential leak interface operates with no identifiable emissions, as applicable using the applicable procedure specified in paragraph (b)(3)(vi)(A) or (B) of this section.

(A) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(3)(vii) of this section.

(B) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(3)(iv) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(3)(vii) of this section.

(vii) A self-contained pneumatic controller is determined to operate with no identifiable emissions if the organic concentration value determined in paragraph (b)(3)(vi) of this section is less than 500 parts per million by volume. An organic concentration value determined in paragraph (b)(3)(vi) of this section of greater than or equal to 500 ppmv constitutes a deviation of the no identifiable emissions standard until an inspection conducted in accordance with this paragraph (b)(3) determines that the self-contained pneumatic controller operates with no identifiable emissions. A potential leak interface is determined to operate with no identifiable emissions if the organic concentration value determined in paragraph (b)(3)(vi) of this section is less than 500 ppmv.

(4) *Repairs.* If emissions or a defect is detected, you must repair the emissions or defect as soon as practicable according to the requirements of paragraphs (b)(4)(i) through (iii) of this section, except as provided in paragraph (b)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the emissions or defect is detected.

(ii) Repair must be completed no later than 30 calendar days after the emissions or defect is detected.

(iii) For covers, grease or another substance compatible with the gasket material must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which emissions or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements of paragraphs (b)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect if the requirements of paragraphs (b)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(8) *Records.* Records shall be maintained as specified in this section and in §60.5420b(c)(6).

**§60.5417b What are the continuous monitoring requirements for my control devices?**

You must meet the requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.

(a) For each control device used to comply with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must meet the specifications and requirements of paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition

of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (*i.e.*, at least once every five minutes) indicates the presence of the pilot flame while emissions are routed to the control device.(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(iv) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(v) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(v)(A) and (B) of this section. You also must monitor the design carbon service life established using a design analysis performed as specified in §60.5413b(c)(2).

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater.

(vi) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in

§60.5413b(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(vii) For a combustion control device whose model is tested under §60.5413b(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(vii)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.

(B) A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame while emissions are routed to the control device.

(viii) For an enclosed combustion control device other than those listed in paragraphs (d)(1)(i) through (iii) and (vii) of this section or for a flare, continuous monitoring systems as specified in paragraphs (d)(1)(viii)(A) through (D) of this section and visible emission observations conducted as specified in paragraph (d)(1)(viii)(E) of this section.

(A) Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

(B) Except as provided in paragraph (d)(1)(viii)(C) of this section, a calorimeter to continuously determine the NHV of the inlet gas to the enclosed combustor or flare at standard conditions. The calorimeter must have a minimum accuracy of ±2 percent of span.

(C) If you demonstrate according to the methods described in paragraphs (d)(1)(ix)(C)(*1*) through (*5*) of this section that the NHV of the inlet gas to the enclosed combustor or flare consistently exceeds the applicable operating limit specified in §60.5415(f)(1)(vii)(B)(*1*) or §60.5415(f)(1)(vii)(C)(*1*), continuous monitoring of NHV is not required. The results of the demonstration must be reported in accordance with §60.5420b(b)(11)(v)(I) and records of the demonstration must be retained in accordance with §60.5420b(c)(11)(ii)(B).

(*1*) Continuously monitor or collect hourly samples of the inlet gas to the enclosed combustor or flare to determine the hourly (or hourly average) NHV of the gas stream for 10 consecutive operating days. If inlet gas flow is intermittent such that there are not at least 200 hourly samples over the 10 operating day period, you must continue to collect hourly samples of the inlet gas beyond the 10 operating day period until you collect a minimum of 200 samples.

(*2*) Count the number of hourly average NHV values that are less than 1.2 times the applicable operating limit specified in §60.5415b(f)(1)(vii)(B)(*1*) or §60.5415b(f)(1)(vii)(C)(*1*) (*i.e.*, values that are less than 240, 360, or 960 Btu/scf, as applicable) during the sample collection period in paragraph (d)(1)(viii)(C)(*1*) of this section.

(*3*) Count the number of hourly average NHV values that are less than the applicable operating limit specified in §60.5415b(f)(1)(vii)(B)(*1*) or §60.5415b(f)(1)(vii)(C)(*1*) (*i.e.*, values that are less than 200, 300, or 800 Btu/scf, as applicable), during the sample collection period in paragraph (d)(1)(viii)(C)(*1*) of this section.

(*4*) If the number of hourly values counted under paragraph (d)(1)(viii)(C)(*2*) of this section is equal to or less than 20 and there are no hourly values counted under paragraph (d)(1)(viii)(C)(*3*) of this section, the gas stream is considered to consistently exceed the applicable NHV operating limit and on-going continuous monitoring is not required.

(*5*) If process operations are revised that could impact the NHV of the gas sent to the enclosed combustor or flare, such as the removal or addition of process equipment, and at any time the Administrator requires, re-evaluation of the gas stream must be performed according to paragraphs (d)(1)(viii)(C)(*1*) through (*4*) of this section to ensure the gas stream still consistently exceeds the applicable operating limit specified in §60.5415b(f)(1)(vii)(B)(*1*) or §60.5415b(f)(1)(vii)(C)(*1*). You must report the process change re-evaluation of the gas stream in accordance with §60.5420b(b)(11)(v)(I) and maintain records in accordance with §60.5420b(c)(11)(ii)(B).

(D) Except as noted in paragraphs (d)(1)(viii)(D)(*1*) through (*4*) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement.

(*1*) If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.

(*2*) If you install and operate a backpressure preventer which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

(*3*) Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(*4*) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(E) Conduct inspections monthly and at other times as requested by the Administrator to monitor for visible emissions from the combustion device using section 11 of Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) Calculate the value of the applicable monitored parameter in accordance with paragraphs (e)(1) through (5) of this section.

(1) You must calculate the daily average value for condenser outlet temperature for each operating day, using the data recorded by the monitoring system. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(2) You must use the hourly inlet gas flow rate to compare with the maximum and minimum inlet flow rate operating limits.

(3) You must use the 5-minute readings from the heat sensing devices to assess the presence of a pilot flame.

(4) You must use the regeneration cycle time (*i.e.*, duration of the carbon bed steaming cycle) for each regenerative-type carbon adsorption system to calculate the average parameter to compare with the maximum steam mass flow or volumetric flow during each carbon bed regeneration cycle and the maximum carbon bed temperature during the steaming cycle. The carbon bed temperature after the regeneration cycle should not be averaged; you must use the carbon bed temperature measured within 15 minutes of completing the cooling cycle to compare with the minimum carbon bed temperature after the regeneration cycle.

(5) For all operating parameters others than those described in paragraphs (e)(1) through (4) of this section, you must calculate the 3-hour rolling average of each monitored parameter. For each operating hour, calculate the hourly value of the operating parameter from your continuous monitoring system. Average the three most recent hours of data to determine the 3-

hour average. Determine the 3-hour rolling average by recalculating the 3-hour average each hour.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412b(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iv) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413b(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412b(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both. If you operate an enclosed combustion control device, you must establish the maximum inlet flow rate based on values measured during the performance test and you may establish the minimum inlet flow rate based on control device manufacturer recommendations.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413b(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412b(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413b(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412b(a)(1), then your control device inlet gas flow rate must be equal to or greater than the minimum inlet gas flow rate and equal to or less than the maximum inlet gas flow rate determined by the manufacturer.

(iv) If you operate an enclosed combustor where the combustion zone temperature is not an indicator of destruction efficiency, you must maintain the net heating value (NHV) of the gas sent to the combustor above the applicable limits specified in paragraphs §60.5412b(a)(1)(iv)(A) through (C).

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413b(b) to demonstrate that the condenser achieves the applicable performance requirements of §60.5412b(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413b(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412b(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (7) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (7) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame present for any time period.

(2) If you are subject to §60.5412b(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415b(f)(1)(ix)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412b(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415b(f)(1)(ix)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411b(a)(4)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411b(a)(4)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413b(d), a deviation occurs when the conditions of paragraphs (g)(4), (g)(5) or (g)(6)(i) through (v) of this section are met.

(i) The hourly inlet gas flow rate is less than the minimum inlet gas flow rate or greater than the maximum inlet gas flow rate determined by the manufacturer.

(ii) Results of the monthly visible emissions test conducted under §60.5413b(e)(3) exceed 1 minute in any 15-minute period.

(iii) There is no indication of the presence of a pilot flame for any 5-minute time period.

(iv) The control device is not maintained in a leak free condition.

(v) The control device is not operated in accordance with the manufacturer’s written operating instructions, procedures and maintenance schedule.

(7) For an enclosed combustor or flare subject to paragraph (d)(1)(viii) of this section, a deviation occurs when any of the conditions described by paragraphs (g)(1), (g)(4) or (g)(5) of

this section are met or when the results of the visible emissions test conducted under paragraph (d)(1)(viii)(E) of this section exceed 1 minute in any 15-minute period.

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

(a) *Notifications.* You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365b that was constructed, modified, or reconstructed during the reporting period. You must submit the notification in paragraph (a)(3) of this section if you use an alternative standard for fugitive emissions components in accordance with §60.5399b. You must submit the notification in paragraph (a)(4) of this section if you undertake well closure activities as specified in §60.5397b(l).

(1) If you own or operate a process unit equipment affected facility located at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station affected facility, you are not required to submit the notifications required in §§60.7(a)(1), (3), and (4) and 60.15(d).

(2) If you own or operate a well affected facility, you must notify the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of

flowback. You may submit the notification in writing or in electronic format. If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of this paragraph.

(3) An owner or operator electing to comply with the provisions of §60.5399b for fugitive emissions components shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraphs (b)(9)(iii) of this section.

(4) An owner or operator who commences well closure activities must submit the following notices to the Administrator according to the schedule in paragraph (a)(4)(i) and (ii) of this section. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well at the well site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983. You must submit notifications in portable document format (PDF) following the procedures specified in paragraph (d) of this section.

(i) You must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.

(ii) You must submit a notification of the intent to close a well site 60 days before you begin well closure activities.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (14) of this section following the procedure specified in paragraph (b)(15) of this section. You must submit performance test reports as specified in paragraph (b)(12) or (13) of this section, if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (14) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period. You must submit the information in paragraph (b)(1)(v), as applicable, for your well affected facility which undergoes a change of ownership during the reporting period, regardless of whether reporting under (b)(2) through (4) is required for the well affected facility.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (b)(1)(iv).

(v) Identification of each well affected facility for which ownership changed due to sale or transfer of ownership including the United States Well Number; the latitude and longitude coordinates of the well affected facility in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the information in paragraph (b)(1)(v)(A) or (B) of this section, as applicable.

(A) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator to which you sold or transferred ownership of the well affected facility identified in paragraph (b)(v) of this section.

(B) The name and contact information, including the phone number, email address, and mailing address, of the owner or operator from whom you acquired the well affected facility identified in paragraph (b)(v) of this section.

(2) For each well affected facility that is subject to §60.5375b(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes all flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section

must also be reported, as applicable. For each well affected facility that is subject to §60.5375b(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported. For each well affected facility which makes a claim that the exemption in §60.5375b(h) was met, the records specified in paragraph (b)(2)(i) through (iv) and (b)(2)(xvi) of this section are required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in §60.5375b(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xiii) For each well affected facility subject to §60.5375b(f), a record of the well type (*i.e.*, wildcat well, delineation well, or low pressure well (as defined §60.5430b)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under §60.5375b(a)(2), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(xvi) For each well affected facility which meets the exemption in §60.5375b(h), a statement that the well completion operation requirements of §60.5375b(a)(1) through (3) were met.

(3) For each well affected facility that is subject to §60.5376b, your annual report is required to include the information specified in paragraphs (b)(3)(i) and (iv) of this section, as applicable. For each well affected facility that you change your liquids unloading method of compliance during the reporting period, you must report that change and submit the applicable information for the new method of compliance as specified in paragraphs (b)(3)(iii) and (iv) of this section.

(i) For each well affected facility where all gas well liquids unloading operations comply with §60.5376b(b), your annual report must include the information specified in paragraphs (b)(3)(i)(A) through (D) of this section.

(A) Identification of each well affected facility that conducts a gas well liquid unloading operation during the reporting period.

(B) Number of gas well liquids unloading operations conducted during the year.

(C) Description of the zero methane and VOC gas well liquids unloading operation method used. If more than one method is used, you must provide a description of each liquids unloading method used during the reporting period.

(D) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If emissions are vented to the atmosphere during a gas well liquids unloading operation, the date and time each emissions event began, the duration in hours that emissions were vented to the atmosphere during each emissions event, and the actions taken to minimize venting to the atmosphere to the maximum extent possible for each emissions event. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(ii) For each well affected facility where all gas well liquids unloading operations comply with §60.5376b(c), your annual report must include the information specified in paragraphs (b)(3)(ii)(A) through (F) of this section.

(A) Identification of each well affected facility that conducts a gas well liquids unloading during the reporting period.

(B) Written justification and documentation as specified in paragraphs (c)(2)(ii)(B)(*1*) and (*2*) of this section of each well affected facility where it is infeasible to utilize a non-zero emitting gas well liquids unloading method for all operations due to technical or safety reasons.

(C) Number of liquids unloading events conducted during the reporting period.

(D) Log of best management practice plan steps used during the reporting period to minimize emissions to the maximum extent possible.

(E) The number of liquids unloading events during the year that best management practices were conducted according to your best management practice plan.

(F) The number of liquids unloading events during the year where deviations from your best management practice plan occurred, the date and time the deviation began, the duration of the deviation in hours, documentation of why best management practice plan steps were not followed, and what steps, in lieu of your best management practice plan steps, were followed to minimize emissions to the maximum extent possible.

(iii) Identification of each well affected facility which changes its gas well liquids unloading zero emitting method of compliance under §60.5376b(b) to a non-zero emitting method of compliance under §60.5376b(c) during the reporting period and the applicable report for the new method of compliance.

(iv) Identification of each well affected facility which changes its gas well liquids unloading non-zero emitting method of compliance under §60.5376b(c) to a zero-emitting method of compliance under §60.5376b(b) during the reporting period and the applicable report for the new method of compliance.

(4) For each oil well with associated gas at your well affected facility subject to §60.5377b, your annual report is required to include the applicable information specified in paragraphs (b)(4)(i) through (v) of this section, as applicable.

(i) For each oil well with associated gas at your well affected facility that complies with §60.5377b(a)(1), (2), (3), or (4) your annual report is required to include the information specified in paragraphs (b)(4)(i)(A) and (B) of this section.

(A) An identification of each oil well with associated gas constructed, modified, or reconstructed during the reporting period that complies with §60.5377b(a)(1), (2), (3), or (4).

(B) Start date, time, and duration in hours of each instance when associated gas was vented and not routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or injected into another well for enhanced oil recovery.

(ii) For each oil well with associated gas at your well affected facility that complies with the requirements of §60.5377b(b) your annual report must include the information specified in paragraphs (b)(4)(ii)(A) through (D) of this section.

(A) An identification of each oil well with associated gas constructed, modified, or reconstructed during the reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent. This identification must include the certification of why it is infeasible to comply with §60.5377b(a)(1), (2), (3), or (4) in accordance with §60.5377b(b)(2).

(B) For each oil well with associated gas constructed, modified, or reconstructed in a previous reporting period that complies by routing the gas to a control device that reduces VOC and methane emissions by at least 95.0 percent, the information in either paragraphs (b)(4)(ii)(B)(*1*) or (*2*) of this section.

(*1*) A statement that no change has been made at the site since the original certification that would impact the ability to comply with §60.5377b(a)(1), (2), (3), or (4).

(*2*) If a change has been made at the site since the original certification, either a re-certification of why it is infeasible to comply with §60.5377b(a)(1), (2), (3), or (4) in accordance with §60.5377b(b)(2), or a statement that indicates compliance can now be achieved with §60.5377b(a)(1), (2), (3), or (4) and a description of specifically how compliance will be achieved.

(C) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent. Include the start date, start time, and duration in hours of each instance.

(D) The information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iii) If you comply with §60.5377b(b) with a control device, identification of the oil well with associated gas using the control device, the information in paragraphs (b)(11)(v) of this section and the report in paragraph (b)(12) or (b)(13) of this section.

(iv) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(v) For each deviation recorded as specified in paragraph (c)(3)(iii) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(5) For each wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. For each dry seal centrifugal compressor or self-contained wet seal centrifugal compressor affected facility, the information specified in paragraphs (b)(5)(vi) and (vii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(4) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) If required to comply with §60.5380b(a)(2), the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iv) If complying with §60.5380b(a)(1) with a control device, identification of the centrifugal compressor with the control device, the information in paragraph (b)(11)(v) of this section, and the report in paragraph (b)(12) or (b)(13) of this section.

(v) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(vi) If complying with §60.5380b(a)(5) dry seal centrifugal compressor or self-contained wet seal centrifugal compressor requirements, the cumulative number of hours of operation since initial startup, since **[INSERT DATE 60 DAYS OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, or since the previous volumetric flow rate emissions measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate emission measurement or emissions screening.

(vii) A description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable.

(6) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(6)(i) through (v) of this section, as applicable.

(i) The cumulative number of hours of operation since initial startup, since **[INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, or since the previous volumetric flow rate measurement, as applicable, which have elapsed prior to conducting your volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(5)(i) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iii) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(iv) If complying with §60.5385b(d), the information in paragraphs (b)(11)(i) through (iv) of this section.

(v) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(7) For each pneumatic controller affected facility, the information specified in paragraphs (b)(7)(i) through (iv) of this section.

(i) An identification of each pneumatic controller affected facility constructed, modified, or reconstructed during the reporting period, including the month and year of installation, reconstruction or modification and for each pneumatic controller which is not part of the affected facility in accordance with §60.5390b(d), identification information that allows traceability to the records required in paragraph (c)(6)(i) of this section.

(ii) For each pneumatic controller affected facility complying with §60.5390b(a), you must report the information specified in paragraphs (b)(7)(ii)(A) and (B), as applicable.

(A) For each pneumatic controller affected facility complying with the routing the emissions to a process requirements of §60.5390b(a)(1), you must report the information specified in (b)(11)(i) through (iv) of this section.

(B) For each pneumatic controller affected facility complying with the standards by using a self-contained natural gas-driven pneumatic controller, you must report the information specified in paragraphs (b)(7)(ii)(B)(*1*) and (*2*).

(*1*) Dates of each inspection required under §60.5416b(b); and

(*2*) Each defect or leak identified during each natural gas-driven-self-contained pneumatic controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each pneumatic controller affected facility located at a site in Alaska that does not have access to electrical power that complies with §60.5390b(b), you must report the information specified in paragraphs (b)(7)(iii)(A), (B), (C) or (D), as applicable.

(A) For each pneumatic controller affected facility complying with §60.5390b(b)(1) pneumatic controller bleed rate requirements, you must report the information specified in paragraphs (b)(7)(iii)(A)(*1*) and (*2*).

(*1*) The identification of pneumatic controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh.

(*2*) Where necessary to meet a functional need, the identification and demonstration why it is necessary to use a pneumatic controller with a natural gas bleed rate greater than 6 scfh.

(B) For each intermittent vent pneumatic controller affected facility complying with the requirements in paragraphs §60.5390b(b)(2), you must report the information specified in paragraphs (b)(7)(iii)(B)(*1*) through (*4*).

(*1*) The identification of each intermittent vent pneumatic controller.

(*2*) Dates and results of monitoring when intermittent vent pneumatic controller is idle.

(*3*) Each leak identified during each intermittent vent pneumatic controller inspection when idling, date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(*4*) For each deviation that occurred during the reporting period and recorded as specified paragraph (c)(6)(iv)(D) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(C) For each pneumatic controller affected facility complying with §60.5390b(b)(3) by routing emissions from all controllers in the pneumatic controller affected facility via a closed vent system to a control device achieving 95.0 percent control, you must report the information specified in paragraphs (b)(11) through (b)(13) of this section and each for deviation that occurred during the reporting period and recorded as specified paragraph (c)(6)(v)(A) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(D) Identification of each pneumatic controller which changes its method of compliance from §60.5390b(b)(1) and (2) to 60.5390b(a) or 60.5390b(b)(3) during the reporting period and the applicable report for the new method of compliance.

(iv) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(7)(ii)(B) and (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(8) For each storage vessel affected facility, the information in paragraphs (b)(8)(i) through (x) of this section.

(i) An identification, including the location, of each storage vessel affected facility, including those for which construction, modification, or reconstruction commenced during the reporting period, and those provided in previous reports. The location of the storage vessel affected facility shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the methane and VOC emission rate determination according to §60.5365b(e)(1) for each tank battery that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(7)(iii) of this section, the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, you must include a statement that no deviations occurred during the reporting period.

(iv) For each storage vessel affected facility constructed, modified, reconstructed, or returned to service during the reporting period complying with §60.5395b(a)(2) with a control device, report the identification of the storage vessel affected facility with the control device and the information in paragraph (b)(11)(v) of this section.

(v) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(vi) If required to comply with §60.5395b(b)(1), the information in paragraphs (b)(11)(i) through (iv) of this section.

(vii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395b(c)(1)(ii), including the date the storage vessel affected facility was removed from service. You must identify each storage vessel that that is removed from service from a storage vessel affected facility during the reporting period as specified in §60.5395b(c)(2)(iii), including identifying the impacted storage vessel affected facility and the date each storage vessel was removed from service.

(viii) You must identify each storage vessel affected facility or portion of a storage vessel affected facility returned to service during the reporting period as specified in §60.5395b(c)(4), including the date the storage vessel affected facility or portion of a storage vessel affected facility was returned to service.

(ix) You must identify each storage vessel affected facility that no longer complies with §60.5395b(a)(3) and instead complies with §60.5395b(a)(2). You must identify whether the change in the method of compliance was due to fracturing or refracturing or whether the change was due to an increase in the monthly emissions determination. If the change was due to an increase in the monthly emissions determination, you must provide documentation of the emissions rate. You must identify the date that you complied with §60.5395b(a)(2) and must submit the information in (b)(8)(iii) through (vii) of this section.

(x) You must submit a statement that you are complying with §60.112b(a)(1) or (2), if applicable, in your initial annual report.

(9) For the fugitive emissions components affected facility, report the information specified in paragraphs (b)(9)(i) through (v) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located.

(B) For the fugitive emissions components affected facility at a well site or centralized production facility that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For the fugitive emissions components affected facility at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For the fugitive emissions components affected facility at a well site, you must specify what type of well site it is (*i.e.*, single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment).

(D) For the fugitive emissions components affected facility at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For the fugitive emissions components affected facility at a well site where you previously reported under paragraph (b)(9)(i)(D) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

(F) For the fugitive emissions components affected facility at a well site where during the reporting period you undertake well closure requirements, the date of the cessation of production from all wells at the well site, the date you began well closure activities at the well site, and the dates of the notifications submitted in accordance with paragraph (a)(4) of this section.

(ii) For each fugitive emissions monitoring survey performed during the annual reporting period, the information specified in paragraphs (b)(9)(ii)(A) through (G) of this section.

(A) Date of the survey.

(B) Monitoring instrument or, if the survey was conducted by visual, audible, or olfactory methods, notation that AVO was used..

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

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

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

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

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

(iii) For the fugitive emissions components affected facility complying with an alternative fugitive emissions standard under §60.5399b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(9)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(9)(i) and (ii) of this section for each individual site complying with the alternative standard.

(iv) For well closure activities which occurred during the reporting period, the information in paragraphs (b)(9)(iv)(A) and (B) of this section.

(A) A status report with dates for the well closure activities schedule developed in the well closure plan. If all steps in the well closure plan are completed in the reporting period, the date that all activities are completed.

(B) If an optical gas imaging survey is conducted during the reporting period, the information in paragraphs (b)(9)(iv)(B)(*1*) through (*3*) of this section.

(*1*) Date of the optical gas imaging survey.

(*2*) Monitoring instrument used.

(*3*) A statement that no fugitive emissions were found, or if fugitive emissions were found, a description of the steps taken to eliminate those emissions, the date of the resurvey, the results of the resurvey, and the date of the final resurvey which detected no emissions.

(v) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(9)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(10) For each pneumatic pump affected facility that is constructed, modified, or reconstructed during the reporting period, the information specified in paragraphs (b)(10)(i) through (xi) of this section.

(i) The identification of each of your pneumatic pumps that are not powered by natural gas, as required by §60.5393b(a) that allows traceability to the records required by paragraph (c)(15)(i) of this section.

(ii) For each pneumatic pump that meets the requirements of §60.5393b(d), the identification of each of the natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power that you collect and route vapors to a process through a closed vent system that allows traceability to the records required by paragraph (c)(15)(ii) of this section and the information specified in paragraphs (b)(11)(i) through (iv) of this section.

(iii) For each pneumatic pump that meets the requirements of §60.5393b(f), the identification of all natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power that you collect and route vapors to a control device through a closed vent system that reduces emissions by 95.0 percent and the information required under paragraphs (b)(11) through (b)(13) of this section.

(iv) For each pneumatic pump affected facility that is constructed, modified or reconstructed during the reporting period that it is technically infeasible to utilize a solar powered pneumatic pump or to utilize a generator to power a compressed air system, the identification of each pneumatic pump that allows traceability to the records in paragraph (c)(15)(iv) of this section and certification that the pneumatic pump meets both of the conditions described in paragraphs (b)(10)(iv)(A) and (B).

(A) Certification that it is technically infeasible to utilize a solar powered pneumatic pump for each pneumatic pump that is part of an affected facility as required under §60.5393b(c)(1).

(B) Certification that it technically infeasible to utilize a generator to power a compressed air system for the pneumatic pump affected facility as required under §60.5393b(c)(2).

(v) For each pneumatic pump affected facility that is constructed, modified or reconstructed during the reporting period that it is technically infeasible to route all of the emissions from all natural gas driven pumps in the affected facility to a process, the identification of each pneumatic pump that allows traceability to the records in paragraph (c)(15)(ii) of this section and a certification that it is technically infeasible to route all of the emissions from all natural gas driven pumps in the affected facility to a process as required under §60.5393b(e).

(vi) For each pneumatic pump affected facility that is constructed, modified or reconstructed during the reporting period that it is technically infeasible to capture and route all of the emissions from all natural gas driven pumps in the affected facility to an existing control device, the identification of each pneumatic pump that allows traceability to the records in paragraph (c)(15)(ix) of this section and a certification of your engineering assessment that there is an existing control device , but that it is technically infeasible to capture and route the emissions to the control device as required under §60.5393b(g)(3).

(vii) For each pneumatic pump affected facility that is constructed, modified or reconstructed during the reporting period where there is no control device available on site, the identification of each pneumatic pump that allows traceability to the records in paragraph (c)(15)(vi) of this section and a certification that there is no control device or process available on site as required under §60.5393b(g)(1).

(viii) For each pneumatic pump affected facility that is constructed, modified or reconstructed during the reporting period where there is a control device available on site but it does not achieve a 95.0 percent reduction, the identification of each pneumatic pump that allows traceability to the records in paragraph (c)(15)(vii) of this section and a certification that there is a control device available on site but it does not achieve a 95.0 percent reduction and the percent emissions reductions the control device is designed to achieve as required under §60.5393b(g)(2).

(ix) For any pneumatic pump affected facility which has previously reported as required under paragraph (b)(10)(i) through (viii) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date that the pneumatic pump affected facility meets one of the change conditions described in paragraphs (b)(10)(ix)(A), (B), or (C) of this section.

(A) If you have the ability to route to a process where you were previously unable, you must report that you now have the ability to route to a process and that the pneumatic pump affected facility now reports according to paragraphs (b)(10)(ii) of this section.

(B) If you install a control device where you were previously unable, you must report that a control device has been added to the location and that the pneumatic pump affected facility now reports according to paragraph (b)(10)(iii) of this section.

(C) If your pneumatic pump affected facility located at a site that does not have access to electrical power was previously routed to a process or a control device and the process or control device is subsequently removed from the location or is no longer available such that there is no ability to route to a process or control device at the location, or that it is not technically feasible to capture and route the emissions to another control device or process located on site, report that you are no longer complying with the applicable requirements of §60.5393b(d) or (f) and submit the information provided in paragraphs (b)(10)(ix)(C)(*1*) or (*2*).

(*1*) Certification that there is no available control device or process on site.

(*2*) Certification of the engineering assessment that it is technically infeasible to capture and route the emissions to another control device or process located on site.

(x) For any deviations recorded as specified in paragraph (c)(15)(x) of this section, the date and time the deviation began, the duration of the deviation in hours, and a description of the deviation.

(xi) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (b)(11)(i) and (ii) of this section, you must provide the information specified in §60.5424b.

(11) For each well, centrifugal compressor, storage vessel, pneumatic controller, pneumatic pump or process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, you must submit the information in paragraphs (b)(11)(i) through (v) of this section. For each reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or process unit equipment which uses a closed vent system to route to a process, you must submit the information in paragraphs (b)(11)(i) through (iv) of this section. For each centrifugal compressor and storage vessel equipped with a cover, you must submit the information in paragraphs (b)(11)(i) and (ii).

(i) Dates of each inspection required under §60.5416b(a) and (b).

(ii) Each defect or leak identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

(iii) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of §60.5416b(a)(4).

(iv) You must submit the certification signed by the qualified professional engineer or in-house engineer according to §60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

(v) If you comply with the emissions standard for your well, centrifugal compressor, storage vessel, pneumatic controller, pneumatic pump or process unit equipment affected facility with a control device, the information in paragraphs (b)(11)(v)(A) through (J) of this section.

(A) Identification of the control device.

(B) Make, model, and date of installation of the control device.

(C) Identification of the affected facility controlled by the device.

(D) For each continuous parameter monitoring system used to demonstrate compliance for the control device, a unique continuous parameter monitoring system identifier and the make, model number, and date of last calibration of the continuous parameter monitoring system.

(E) For each instance where there is a deviation of the control device in accordance with §60.5417b(g)(1) through (3) or (5) through (7) include the date and time the deviation began, the duration of the deviation in hours, the type of the deviation (combustion device operating limit, lack of pilot flame, condenser efficiency, bypass line flow, visible emissions, etc.), and cause of the deviation (startup/shutdown, control equipment problems, process problems, other known causes, or unknown causes).

(F) For each instance where there is a deviation of the continuous parameter monitoring system in accordance with §60.5417b(g)(4) include the date and time the deviation began, the duration of the deviation in hours, and cause of the deviation (monitor equipment malfunction, non-monitor equipment malfunctions, quality assurance calibration, other known causes, or unknown causes).

(G) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test in minutes, and the number of minutes for which visible emissions were present.

(H) If a performance test was conducted on the control device during the reporting period, provide the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(12) of this section.

(I) If a demonstration of the NHV of the inlet gas to the enclosed combustor or flare was conducted during the reporting period, the applicable NHV operating limit, number of hourly average NHV values that are less than 1.2 times the applicable operating limit according to paragraph §60.5417b(d)(1)(ix)(C)(*2*), the number of hourly average NHV values that are less than the applicable operating limit according to paragraph §60.5417b(d)(1)(ix)(C)(*3*), and the resulting determination of whether NHV monitoring is required or not in accordance with §60.5417b(d)(1)(viii)(C).

(J) If a demonstration that the maximum potential pressure of units manifolded to an enclosed combustor or flare cannot cause the maximum inlet flow rate established in accordance with §60.5417b(f)(1) or the flare tip velocity limit established in accordance with §60.18 to be exceeded, the demonstration and applicable engineering calculations.

(12) Within 60 days after the date of completing each performance test (see §60.8) required by this subpart, except testing conducted by the manufacturer as specified in §60.5413b(d), you must submit the results of the performance test following the procedures specified in paragraph (d) of this section. Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not

supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(13) For combustion control devices tested by the manufacturer in accordance with §60.5413b(d), an electronic copy of the performance test results required by §60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.

(14) For each super-emitter affected facility which had a super-emitter emissions event during the reporting period, the start date of the super-emitter emissions event, the duration of the super-emitter emissions event in hours, and the emissions source affected facility associated with the super-emitter emissions event, if applicable.

(15) You must submit your annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for this subpart and following the procedure specified in paragraph (d) of this section. If the reporting form specific to this subpart is not available on the CEDRI website 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 on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (15) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(1) The records for each well affected facility subject to the well completion operation standards of §60.5375b, as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility subject to the well completion operations of §60.5375b, for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to §60.5375b(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility which meets the exemption in §60.5375b(h) for well completion operations (*i.e.*, an existing well is hydraulically refractured), you must maintain the records in paragraph (c)(1)(viii), only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375b, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of §60.5375b(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375b(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375b(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in §60.5375b(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in §60.5375b(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of §60.5375b(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of combustion; duration of venting; and specific reasons for venting in lieu combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of §60.5375b(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of §60.5375b(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under §60.5375b(a)(2), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both §60.5375b(a)(1) and (2), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410b(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to §60.5375b(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to §60.5375b(f), a record of the well type (*i.e.*, wildcat well, delineation well, or low pressure well (as defined §60.5430b)) and supporting inputs and calculations, if applicable.

(viii) For each well affected facility which makes a claim it meets the exemption at §60.5375b(h), a record of the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing and a record of the claim that the well completion operation requirements of §60.5375b(a)(1) through (3) were met.

(2) For each gas well liquids unloading operation at your well affected facility that is subject to §60.5376b(b) or (c), the records of each gas well liquids unloading operation conducted during the reporting period, including the information specified in paragraphs (c)(2)(i) and (ii) of this section, as applicable. For each well affected facility that you change your liquids unloading method of compliance, you must retain records of that change as specified under paragraphs (c)(2)(iii) or (iv) of this section, as applicable.

(i) For each gas well liquids unloading operation that complies with §60.5376b(b) by performing all liquids unloading events with zero methane and VOC emissions, comply with the recordkeeping requirements specified in paragraphs (c)(2)(i)(A) through (C) of this section.

(A) Identification of each well that conducts a gas well liquids unloading operation during the reporting period.

(B) Description of the zero methane and VOC gas well liquids unloading method that was used for each gas well liquids unloading operation.

(C) For each deviation that occurred during the reporting period, the date and time the deviation began, the duration of the deviation, and a description of the deviation. If emissions are vented to the atmosphere during a gas well liquids unloading operation, the date and time of each emissions event, the duration that emissions were vented to the atmosphere during each emissions event and the actions that were taken to minimize venting to the atmosphere to the maximum extent possible for each emissions event.

(ii) For each gas well liquids unloading operation that complies with §60.5376b(c), maintain records documenting information specified in paragraphs (c)(2)(ii)(A) through (E) of this section.

(A) Identification of each well affected facility that conducts liquids unloading during the reporting period.

(B) Written justification and documentation as specified in paragraphs (c)(2)(ii)(A)(*1*) and (*2*) of this section of why it is infeasible to utilize a zero emitting method to unload liquids at the well affected facility due to technical or safety reasons.

(*1*) Written justification needs to include supporting information justifying why it is infeasible to utilize a non-zero emitting liquids unloading method at the well affected facility due to technical or safety reasons (*e.g.,* related to a well's operating conditions and reservoir energy with respect to well-bore liquid management).

(*2*) Technical and safety reasons provided as support need to be certified by a professional engineer or another qualified individual with expertise in liquids unloading operations. The following certification, signed and dated by the qualified professional engineer of other qualified individual shall state: "I certify that the technical and safety infeasibility justification of needing to use a non-zero emitting liquids unloading method for all liquids unloading events at the well affected facility was prepared under my direction or supervision. Based on my professional knowledge and experience, and inquiry of personnel involved in the infeasibility justification, the certification submitted herein is true, accurate, and complete."

(C) Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).

(D) A log of each best management practice plan step taken minimize emissions to the maximum extent possible for each gas well liquids unloading event.

(E) Documentation of each gas well liquids unloading event where deviations from your best management practice plan steps occurred, the date and time the deviation began, the duration of the deviation, documentation of best management practice plans steps were not followed, and the steps taken in lieu of your best management practice plan steps during those events to minimize emissions to the maximum extent possible.

(iii) For each well affected facility that changes its method of compliance for all liquids unloading operations from the zero emitting standard requirements under §60.5376b(b) to the non-zero emitting standard requirements under §60.5376b(c), retain records of this change and the records required under paragraph (c)(2)(ii) of this section.

(iv) For each well affected facility that changes its method of compliance for all liquids unloading operations from non-zero emitting standard requirements under §60.5376b(c) to the zero emitting standard requirements under §60.5376b(b), retain records of this change and the records required under paragraph (c)(2)(i) of this section.

(3) For each oil well with associated gas at your well affected facility, you must maintain the applicable records specified in paragraphs (c)(3)(i) or (ii) and (iv) of this section.

(i) For each oil well with associated gas at your well affected facility that complies with the oil well with associated gas requirements of §60.5377b(a)(1), (2), (3), or (4), you must keep the records specified in paragraphs (c)(3)(i)(A) and B).

(A) Documentation of the specific method in §60.5377b(a)(1), (2), (3), or (4) that was used.

(B) A record of each instance when associated gas was vented and not routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or injected into another well for enhanced oil recovery.

(ii) For each oil well with associated gas at your well affected facility that complies with the requirements of §60.5377b(b) because it has demonstrated that it is not feasible to comply with §60.5377b(a)(1), (2), (3), or (4) due to technical or safety reasons, meet the recordkeeping requirements specified in paragraphs (c)(3)(ii)(A) through (H).

(A) Records of your demonstration and certification of the technical or safety reason that it is not feasible to comply with §60.5377b(a)(1), (2), (3), or (4) in accordance with 60.5377b(b)(1) and (b)(2).

(B) Records of each change been made at the site since the original certification along with records of either a re-certification of why it is infeasible to comply with §60.5377b(a)(1), (2), (3), or (4) in accordance with §60.5377b(b)(2), or a statement that indicates compliance can now be achieved with §60.5377b(a)(1), (2), (3), or (4) and a description of specifically how compliance will be achieved.

(C) Identification of each instance when associated gas was vented and not routed to a control device that reduces VOC and methane emissions by at least 95.0 percent.

(D) If you comply with the emission reduction standard in §60.5380b with a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), the information in paragraph (c)(11)(i) of this section.

(E) If you comply with the emission reduction standard in §60.5380b with a control device not tested under §60.5413b(d), the information for each control device in paragraph (c)(11)(ii) of this section.

(F) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must maintain records of the information specified in §60.5424b.

(G) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(H) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(4) For each centrifugal compressor affected facility, you must maintain the records specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(ii) For each wet seal compressor complying with the emissions reduction standard in §60.5380b(a)(1), you must maintain the records in paragraphs (c)(4)(ii)(A) through (F) of this section. For each wet seal compressor complying with the alternative standard in §60.5380b(a)(3) by routing the closed vent system to a process, you must maintain the records in paragraphs (c)(4)(ii)(C) through (F) of this section.

(A) If you comply with the emission reduction standard in with a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), the information in paragraph (c)(11)(i) of this section.

(B) If you comply with the emission reduction standard with a control device not tested under §60.5413b(d), the information for each control device in paragraph (c)(11)(ii) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must maintain the information specified in §60.5424b.

(D) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must maintain the information specified in §60.5424b.

(E) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(F) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

(iii) For each centrifugal compressor affected facility using dry seals or each self-contained wet seal compressor complying with the standard in §60.5380b(a)(4) and (5), you must maintain the records specified in paragraphs (c)(4)(iii)(A) through (C) of this section.

(A) Records of the cumulative number of hours of operation since initial startup, since **[INSERT DATE 60 DAYS OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, or since the previous volumetric flow rate measurement, as applicable.

(B) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(C) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(4)(iii)(C)(*1*) through (*7*).

(*1*) Description of standard method published by a consensus-based standards organization or industry standard practice.

(*2*) Record of each of three duration to fill calibrated bag and average of the three readings, if applicable.

(*3*) Records of volumetric flow rate emissions calculations conducted according to paragraphs §60.5380b(a)(5), as applicable.

(*4*) Records of manufacturer operating procedures and measurement methods.

(*5*) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(*6*) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(*7*) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(5) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(5)(i) through (vi), and (c)(8), (c)(10) and (c)(12) of this section, as applicable. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must provide the information specified in §60.5424b.

(i) For each reciprocating compressor affected facility, you must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

(ii) Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385b(d).

(iii) Records of the cumulative number of hours of operation since initial startup, since **[INSERT DATE 60 DAYS OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

(iv) A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

(v) Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs (c)(5)(v)(A) through (G).

(A) Description of standard method published by a consensus-based standards organization or industry standard practice.

(B) Record of each of three duration to fill calibrated bag and average of the three readings, if applicable.

(C) Records of volumetric flow rate calculations conducted according to paragraphs §60.5385b(b) or (c), as applicable.

(D) Records of manufacturer operating procedures and measurement methods.

(E) Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration and accuracy checks.

(F) Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. You must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

(G) Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

(6) For each pneumatic controller affected facility, you must maintain the records specified in paragraphs (c)(6)(i) through (v) of this section.

(i) Records identifying each pneumatic controller that is not part of an affected facility and the basis for that claim. The basis for a claim can be made for pneumatic controllers that meet the conditions specified in paragraphs (c)(6)(i)(A) and (B).

(A) Natural gas-driven pneumatic controllers that function as emergency shutdown devices.

(B) Pneumatic controllers that are not driven by natural gas.

(ii) For each pneumatic controller affected facility complying with §60.5390b(a), you must maintain records of the information specified in paragraphs (c)(6)(ii)(A) and (B), as applicable.

(A) For each pneumatic controller affected facility complying with the routing the emissions to a process requirements of §60.5390b(a)(1), you must maintain records of the information specified in paragraphs (c)(8), (c)(10), and (c)(12) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must provide the information specified in §60.5424b.

(B) For each pneumatic controller affected facility complying with the standards by using a self-contained natural gas-driven pneumatic controller, you must report the information specified in paragraphs (c)(6)(ii)(B)(*1*) and (*2*).

(*1*) Dates of each inspection required under §60.5416b(b); and

(*2*) Each defect or leak identified during each natural gas-driven-self-contained pneumatic controller system inspection, and date of repair or date of anticipated repair if repair is delayed.

(iii) For each pneumatic controller affected facility complying with §60.5390b(b)(1) pneumatic controller bleed rate requirements, you must maintain records of the information specified in paragraphs (c)(6)(iii)(A) and (B).

(A) The identification of pneumatic controllers designed and operated to achieve a bleed rate less than or equal to 6 scfh and records of the manufacturers specifications indicating that the pneumatic controller is designed with a natural gas bleed rate is less than or equal 6 scfh.

(B) Where necessary to meet a functional need, the identification of the pneumatic controller and demonstration why it is necessary to use a pneumatic controller with a natural gas bleed rate greater than 6 scfh.

(iv) For each intermittent vent pneumatic controller affected facility complying with the requirements in paragraphs §60.5390b(b)(2), you must keep records of the information specified in paragraphs (c)(6)(iv)(A) through (D).

(A) The identification of each intermittent vent pneumatic controller.

(B) Dates and results of monitoring when intermittent vent pneumatic controller is idle.

(C) Each leak identified during each intermittent vent pneumatic controller inspection when idling, date of repair or replacement, or the date of anticipated repair or replacement if the repair or replacement is delayed and the date and results of the re-survey after repair or replacement.

(D) Records of each deviation, the date and time the deviation began, the duration of the deviation (in hours), and a description of the deviation.

(v) For each pneumatic controller affected facility complying with §60.5390b(b)(3), you must maintain the records specified in paragraphs (c)(6)(v)(A) and (B) of this section.

(A) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390b, including a description of each deviation, the date and time each deviation began and the duration of each deviation.

(B) Records specified in paragraphs (c)(8), (c)(10) through (c)(13). If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must provide the information specified in §60.5424b.

(7) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(7)(i) through (vii) of this section.

(i) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(ii) Records of each methane and VOC emissions determination for each storage vessel affected facility made under §60.5365b(e) including identification of the model or calculation methodology used to calculate the methane and VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in §§60.5395b a description of the deviation, the date and time each deviation began, and the duration of the deviation.

(iv) If complying with the emissions reduction standard in §60.5380b(a)(1), you must maintain the records in paragraphs (c)(7)(iv)(A) through (E) of this section.

(A) If you comply with the emission reduction standard in with a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), the information in paragraph (c)(11)(i) of this section.

(B) If you comply with the emission reduction standard with a control device not tested under §60.5413b(d), the information for each control device in paragraph (c)(11)(ii) of this section.

(C) Records of the closed vent system inspection as specified paragraph (c)(8) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(8) of this section, you must provide the information specified in §60.5424b.

(D) Records of the cover inspections as specified in paragraph (c)(9) of this section. If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(9) of this section, you must provide the information specified in §60.5424b.

(E) If applicable, the records of bypass monitoring as specified in paragraph (c)(10) of this section.

(F) Records of the closed vent system assessment as specified in paragraph (c)(12) of this section.

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

(vi) Records of the date that each storage vessel affected facility or portion of a storage vessel affected facility is removed from service and returned to service, as applicable.

(vii) Records of the date that liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility; or the date that you comply with paragraph §60.5395b(a)(2), following a monthly emissions determination which indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater or methane emissions increase to 14 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, and records of the methane and

VOC emissions rate and the model or calculation methodology used to calculate the methane and VOC emission rate.

(8) Records of each closed vent system inspection required under §60.5416b(a)(1) and (2) and (b) for your well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected facility as required in paragraphs (c)(8)(i) through (iii) of this section.

(i) A record of each closed vent system inspection or no identifiable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect or leak detected during inspections required by §60.5416b(a)(1) and (2), or (b) you must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of appendix A-7 of this part, the date of detection, and the date the repair to correct the defect or leak is completed.

(iii) If repair of the defect is delayed as described in §60.5416b(b)(5), you must record the reason for the delay and the date you expect to complete the repair.

(9) A record of each cover inspection required under §60.5416b(a)(3) for your centrifugal compressor or storage vessel as required in paragraphs (c)(9)(i) through (iii) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect detected during the inspection you must record the location of the defect, a description of the defect, the date of detection, the corrective action taken the repair the defect, and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in §60.5416b(b)(5), you must record the reason for the delay and the date you expect to complete the repair.

(10) For each bypass subject to the bypass requirements of §60.5416b(a)(4), you must maintain a record of each inspection. a record of each time the key is checked out, or a record of each time the alarm is sounded, as applicable.

(11) Records for each control device for your well, centrifugal compressor pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected facility as required in paragraphs (c)(11)(i) and (ii) of this section.

(i) If you comply with the emission reduction standard in §60.5377b(b) for oil well with associated gas, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or §60.5400b(f) or 60.5401b(e) for your process equipment affected facility with a control device tested under §60.5413b(d) which meets the criteria in §60.5413b(d)(11) and (e), the information in paragraphs (c)(11)(i)(A) through (H) of this section.

(A) Make, model, and serial number of purchased device.

(B) Date of installation.

(C) Copy of purchase order.

(D) Location of the affected facility associated with the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413b(e) as specified in paragraphs (c)(11)(i)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period. You must maintain records of Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 of this part.

(*3*) Records of the maintenance and repair log as specified in §60.5412b(d)(1)(iii), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present. You must maintain records of Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 of this part.

(*5*) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(*6*) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, and results of all compliance calculations. In lieu of records of minimum inlet flow rate, the name, date of installation and record of inlet flow rating for backpressure preventer.

(*7*) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan in accordance with §60.5417b(c)(2) and deviations according to §60.5417b(g)(4).

(*8*) Records of the performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan required by §60.5417b(c)(2).

(G) Records of deviations in accordance with §60.5417b(g)(6), including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(H) As an alternative to the requirements of paragraph (c)(11)(i)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the oil well with associated gas and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the oil well with associated gas and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(ii) If you comply with the emission reduction standard in §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or §60.5400b(f) or 60.5401b(e) for your process equipment affected facility with a control device not tested under §60.5413b(d), the information for each control device in paragraphs (c)(11)(ii)(A) through (G) of this section.

(A) Records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections. You must maintain records of Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in Method 22 of appendix A-7 of this part. In lieu of minimum inlet flow rate records, the name, date of installation and record of inlet flow rating for backpressure preventer.

(B) Records of the demonstration of the NHV of the inlet gas to the enclosed combustor and records of process changes and resulting re-determination of the NHV in accordance with §60.5417b(d)(1)(viii)(C).

(C) Records of deviations in accordance with §60.5417b(g)(1) through (3), (5), and (7), including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(D) Records of continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan in accordance with §60.5417b(c)(2) and deviations according to §60.5417b(g)(4).

(E) Records of the performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan required by §60.5417b(c)(2).

(F) For each carbon adsorption system, records of the schedule for carbon replacement as determined by the design analysis requirements of §60.5413b(c)(2) and (3) and records of each carbon replacement as specified in §60.5412b(c)(1) and §60.5415b(f)(1)(viii).

(G) Records of the demonstration that the maximum potential pressure of affected facility emissions manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph §60.5417b(f)(1) or the flare tip velocity limit in §60.18 to be exceeded,

(12) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411b(d):

(i) A copy of the assessment conducted according to §60.5411b(d)(1); and

(ii) A copy of the certification according to §60.5411b(d)(1)(i).

(13) A copy of each performance test submitted under paragraphs (b)(12) or (13) of this section.

(14) For the fugitive emissions components affected facility, maintain the records identified in paragraphs (c)(14)(i) through (viii) of this section.

(i) The date of the startup of production or the date of the first day of production after modification for the fugitive emissions components affected facility at a well site and the date of startup or the date of modification for the fugitive emissions components affected facility at a compressor station.

(ii) For the fugitive emissions components affected facility at a well site, you must maintain records specifying what type of well site it is (*i.e.,* single wellhead only well site, small wellsite, multi-wellhead only well site, or a well site with major production and processing equipment.)

(iii) For the fugitive emissions components affected facility at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

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

(v) The records of each monitoring survey as specified in paragraphs (c)(14)(v)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument or method used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 of this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.*, operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

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

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

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(14)(v)(I)(*1*) through (*8*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A-7 of this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.*, tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

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

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

(vi) For the fugitive emissions components affected facility complying with an alternative means of emissions limitation under §60.5399b, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(vii) For well closure activities, you must maintain the information specified in paragraphs (c)(14)(iv)(A) through (G) of this section.

(A) The well closure plan developed in accordance with §60.5397b(l) and the date the plan was submitted.

(B) The notification of the intent to close the well site and the date the notification was submitted.

(C) The date of the cessation of production from all wells at the well site.

(D) The date you began well closure activities at the well site.

(E) Each status report for the well closure activities reported in paragraph (b)(9)(iv)(A) of this section.

(F) Each optical gas imaging survey reported in paragraph (b)(9)(iv)(B) of this section including the date, the monitoring instrument used, and the results of the survey or resurvey.

(G) The final optical gas imaging survey video demonstrating the closure of all wells at the site. The video must include the date that the video was taken and must identify the well site location by latitude and longitude.

(viii) If you comply with an alternative GHG and VOC standard under §60.5398b, in lieu of the information specified in paragraphs (c)(14)(iv) through (v) of this section, you must provide the information specified in §60.5424b.

(15) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(15)(i) through (ix) of this section.

(i) Identification of each pneumatic pump that is not driven by natural gas or single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year and is not a pneumatic pump affected facility as specified in §60.5365b(h).

(ii) Identification of all the natural gas-driven pneumatic pumps in the pneumatic pump affected facility located at a site that does not have access to electrical power that you collect and route vapors to a process through a closed vent system as required by §60.5393b(d) and the records specified in paragraphs (c)(8), (c)(10), and (c)(12) of this section. If you demonstrate that it is technically infeasible to route the emissions to a process through a closed vent system, records of your demonstration and certification that it is technically infeasible as required by §60.5393b(e).

(iii) If the pneumatic pump affected facility is routed to a process and the process is subsequently removed from the location or is no longer available such that there is no ability to route to a process at the location, retain records of this change and the records required under paragraph (c)(15)(v) of this section.

(iv) For pneumatic pump affected facilities that you make a demonstration that it is technically infeasible to use either a solar powered pneumatic pump or technically infeasible to use a generator to power a compressed air system, records of your demonstration and certification that it is technically infeasible as required by §60.5393b(c)(1) and (2).

(v) If you reduce methane and VOC emissions from all natural gas-driven pneumatic pumps in the pneumatic pump affected facility by 95.0 percent by routing all emissions to a control device through a closed vent system as required by §60.5393b(f), you must keep the records specified in paragraphs (c)(8) and (c)(10) through (c)(13).

(vi) If you have less than four natural gas-driven pumps in the pneumatic pump affected facility, and you do not have a control device installed on site by the compliance date, you must retain a record of your certification required under §60.5393b(g)(1), certifying that there is no available control device on site. If you subsequently install a control device or have the ability to route to a process, you must maintain the records required under paragraphs (c)(15)(ii) or (c)(14)(v) of this section, as applicable.

(vii) If you have a control device available on site but it is unable to achieve a 95.0 percent reduction, and you route the pneumatic pump affected facility emissions to that control device as required under §60.5393b(g)(2), you must maintain records of the certification that there is a control device on site but it does not achieve a 95.0 percent reduction and record of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(viii) If you determine, through an engineering assessment, that it is technically infeasible to route the pneumatic pump affected facility emissions to a control device, you must retain records of your demonstration and certification that it is technical infeasible as required under §60.5393b(g)(3).

(ix) If the pneumatic pump is routed to a control device that is subsequently removed from the location or is no longer available such that there is no option to route to a control device, you are required to retain records of this change and the records required under paragraph (c)(15)(vi) of this section.

(x) Records of each deviation, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(d) *Electronic reporting.* If you are required to submit notifications or reports following the procedure specified in this paragraph (d), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA’s CDX as described earlier in this paragraph (d).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address

oaqpscbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Oil and Natural Gas Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Oil and Natural Gas Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(e) *Claims of EPA system outage.* If you are required to electronically submit a notification or report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) *Claims of force majeure.* If you are required to electronically submit a report or notification through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (f)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force*

*majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

**§60.5421b What are my additional recordkeeping requirements for process unit equipment affected facilities?**

You must maintain a record of each equipment leak monitoring inspection and each leak identified under §60.5400b and §60.5401b as specified in paragraphs (b)(1) through (16) of this section. The record must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(a) You may comply with the recordkeeping requirements for multiple process unit equipment affected facilities in one recordkeeping system if the system identifies each record by each facility.

(b) You must maintain the monitoring inspection records specified in paragraphs (b)(1) through (16) of this section.

(1) Equipment Identification. Note that connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

(2) Date and start and end times of the monitoring inspection.

(3) Inspector name.

(4) Leak determination method used for the monitoring inspection (*i.e.*, optical gas imaging, Method 21, or visual, audible, olfactory).

(5) Monitoring instrument identification (optical gas imaging and Method 21 only).

(6) Type of equipment monitored.

(7) Process unit identification.

(8) The records specified in Section 12 of appendix K of this part, for each monitoring inspection conducted with optical gas imaging.

(9) The records in paragraph (b)(9)(i) through (vii), for each monitoring inspection conducted with Method 21 of appendix A-7 of this part.

(i) Instrument reading.

(ii) Date and time of instrument calibration and initials of operator performing the calibration.

(iii) Calibration gas cylinder identification, certification date, and certified concentration.

(iv) Instrument scale used.

(v) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

(vi) Results of the daily calibration drift assessment.

(vii) If you make your own calibration gas, a description of the procedure used.

(10) For visual inspections of pumps in light liquid service, keep the records specified in paragraphs (b)(10)(i) through (iii), for each monitored equipment:

(i) Date of inspection.

(ii) Inspector name.

(iii) Result of inspection (*i.e.*, visual indications of liquids dripping from the pump seal or no visual indications of liquids dripping from the pump seal).

(11) For each leak detected, the records specified in paragraphs (b)(11)(i) through (v), of this section:

(i) The instrument and operator identification numbers and the process unit and equipment identification numbers. For leaks identified via visual, olfactory, audible methods, enter the specific sensory method for instrument identification number.

(ii) The date the leak was detected.

(iii) For each attempt to repair the leak, record:

(A) The date.

(B) The repair method applied.

(C) Indication of whether a leak was still detected following each attempt to repair the leak.

(vi) The date of successful repair of the leak and the method of monitoring used to confirm the repair, as specified in paragraph (b)(11)(vi)(A) through (C) of this section.

(A) If Method 21 of appendix A-7 of this part is used to confirm the repair, maintain a record of the maximum instrument reading measured by Method 21 of appendix A-7 of this part.

(B) If optical gas imaging conducted in accordance with Appendix K of this part is used to confirm the repair, maintain a record of video footage of the repair confirmation.

(C) If the leak is repaired by eliminating visual, audible, or olfactory indications of a leak, maintain a record of the specific sensory method used to confirm that the evidence of the leak is eliminated.

(v) For each repair delayed beyond 15 calendar days after detection of the leak, record:

(A) “Repair delayed” and the reason for the delay.

(B) The signature of the certifying official who made the decision that repair could not be completed without a process shutdown.

(C) The expected date of successful repair of the leak.

(D) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(12) A list of identification numbers for equipment that are designated for no detectable emissions complying with the provisions of §60.5401b.

(13) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(14) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(15) A list of identification numbers for equipment that is in vacuum service.

(16) A list of identification numbers for equipment you designate as having the potential to emit methane or VOC less than 300 hrs/yr.

**§60.5422b What are my additional reporting requirements for process unit equipment affected facilities?**

(a) You must submit semiannual reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in §60.5420b(d). If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted within 45 days after the end of the semiannual reporting period, regardless of the method in which the report is submitted.

(b) The initial semiannual report must include the following information:

(1) The general information specified in paragraph (c)(1) of this section.

(2) For each process unit:

(i) Process unit identification.

(ii) Number of valves subject to the monitoring requirements of §60.5400b(b) and §60.5401b(f).

(iii) Number of pumps subject to the monitoring requirements of §60.5400b(b) and §60.5401b(b).

(iv) Number of connectors subject to the monitoring requirements of §60.5400b(b) and §60.5401b(h).

(v) Number of pressure relief devices subject to the monitoring requirements of §60.5400b(b) and §60.5401b(c).

(vi) The information in paragraphs (c)(3) and (4) of this section.

(c) All subsequent semiannual reports must include the following information:

(1) The general information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) The company name, facility site name, and address of the affected facility.

(ii) Beginning and ending dates of the reporting period.

(iii) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (c)(1)(iii).

(2) Process unit identification for each process unit.

(3) For each month during the semiannual reporting period for each process unit report:

(i) Number of valves for which leaks were detected as described in §60.5400b(b) or §60.5401b(f).

(ii) Number of valves for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(iii) Number of pumps for which leaks were detected as described §60.5400b(b) or §60.5401b(b).

(iv) Number of pumps for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(v) Number of connectors for which leaks were detected as described in §60.5400b(b) or §60.5401b(h).

(vi) Number of connectors for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(vii) Number of pressure relief devices for which leaks were detected as described in §60.5400b(b) or §60.5401b(c).

(viii) Number of pressure relief devices for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(ix) Number of open-ended valves or lines for which leaks were detected as described in §60.5400b(e) or §60.5401b(d).

(x) Number of open-ended valves or lines for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(xi) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were detected as described in §60.5400b(g) or §60.5401b(g).

(xii) Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were not repaired as required in §60.5400b(h) or §60.5401b(i).

(xiii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(4) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(5) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

**§60.5423b What are my additional recordkeeping and reporting requirements for sweetening unit affected facilities?**

(a) You must retain records of the calculations and measurements required in §§60.5405b(a) and (b) and 60.5407b(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) In your initial annual report submitted in accordance with the procedures and schedule in §60.5420b(b), include the information in paragraphs (b)(1) and (2) of this section.

(1) For each run of the initial performance test required by §60.8(b):

(i) The average sulfur feed rate in Mg/D, determined according to §60.5406b(b).

(ii) The average volumetric flow rate of acid gas from the sweetening unit, in dscm/day.

(iii) The $H_2S$ concentration in the acid gas feed from the sweetening unit, percent by volume.

(iv) The emission rate of sulfur in kg/hr.

(v) The sulfur production rate in kg/hr.

(vi) The emission reduction efficiency achieved by the sulfur recovery technology, determined according to §60.5406b(c).

(vii) The required initial $SO_2$ emission reduction efficiency, as determined from Table 3 of this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(2) The required minimum $SO_2$ emission reduction efficiency you must achieve on a continuous basis, as determined from Table 4 of this subpart based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.

(c) You must submit the performance test report in accordance with the requirements of §60.5420b(b)(12).

(d) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures and schedule for submitting annual reports are located in §60.5420b(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (d)(1) and (2) of this section. The report must contain the information specified in paragraph (d)(3) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407b(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407b(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (d)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (d)(2) of this section.

(e) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of $H_2S$ in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of $H_2S$ expressed as sulfur.

(f) If you elect to comply with §60.5407b(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(g) The requirements of paragraph (d) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (d) of this section, provided they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

**§60.5424b What are my additional recordkeeping and reporting requirements if I comply with the alternative GHG and VOC standards for fugitive emissions components affected facilities and covers and closed vent systems?**

This section provides notification, reporting, and recordkeeping requirements for owners and operators who choose to comply with an alternative GHG and VOC standard as specified in §60.5398b for fugitive emissions components affected facilities or the alternative initial and continuous compliance requirements for covers and closed vent systems. You must submit an annual report in accordance with the schedule in §60.5420b(b) which includes the information in paragraphs (a)(1), (b), and (d) of this section, as applicable. You must submit the notification in paragraph (a)(2) of this section and maintain the records in paragraphs (c) and (e) of this section, as applicable.

(a) *Notifications*. If you choose to comply with an alternative GHG and VOC standard as specified in §60.5398b for fugitive emissions components affected facilities or the alternative initial and continuous compliance requirements for covers and closed vent systems, you must submit the notification in paragraph (a)(1) of this section. If upon completion of the initial corrective actions required under §60.5398b(c)(6), the continuous monitor readings are not below the action levels in §60.5398b(c)(4)(i)(B) or §60.5398b(c)(4)(ii)(B) for the next 24-hour sampling period or if all corrective action measures identified to reduce methane and VOC emissions require more than 30 days to implement, you must develop a corrective action plan and submit the notification in paragraph (a)(2) of this section.

(1) A notification to the Administrator of adoption of the alternative standards in the annual report required by §60.5420b(b)(4) through (b)(11).

(2) A notification, which includes the submittal of the corrective action plan required by §60.5398b(c)(7). You must submit the corrective action plan to the Administrator within 60 days of the initial exceedance of the action level.

(b) If you comply with the periodic screening requirements of §60.5398b(b), you must submit the information in paragraphs (b)(1) through (6) of this section in the annual report required by §60.5420b(b)(4) through (b)(11).

(1) Date of each periodic screening during the reporting period and date that results of the periodic screening were received.

(2) Alternative test method and technology used for each screening.

(3) Any deviations from the fugitives monitoring plan developed under §60.5398b(b)(1) or a statement that there were no deviations from the monitoring plan.

(4) Results from each periodic screening during the reporting period. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, you must submit the information in paragraphs (b)(4)(i) through (iv) of this section.

(i) The date that the monitoring survey of your entire fugitive emissions components affected facility was conducted.

(ii) The date that you completed the instrument inspections of all your covers and closed vent systems(s).

(iii) The date that you conducted the visual inspection for leaks of the closed vent systems and covers.

(iv) For each fugitive emission from a fugitive emissions components affected facility and each leak or defect for each cover and closed vent system inspection, you must submit the information in paragraphs (b)(4)(iv)(A) through (D) of this section.

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

(B) Each leak or defect identified during the inspection for each cover and closed vent system.

(C) Date of repair for each fugitive emission from a fugitive emissions components affected facility or each leak or defect for each cover and closed vent system.

(D) Number and type of fugitive emission components and identification of each cover or closed vent system placed on delay of repair and an explanation for each delay of repair.

(5) The information in paragraphs (b)(5)(i) through (iv) of this section if you are required to conduct OGI surveys in accordance with §60.5398b(b)(3).

(i) The date of the OGI survey.

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

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

(iv) Number and type of fugitive emission components placed on delay of repair and an explanation for each delay of repair.

(6) Any additional information regarding the performance of the periodic screening technology as specified by the Administrator, as part of the alternative test method approval described in §60.5398b(d).

(c) If you comply with the periodic screening requirements of §60.5398b(b), you must maintain the records in paragraphs (c)(1) through (10) of this section in addition to the records specified in as specified in §60.5420b(c)(3) through (9) and (c)(14) and (15).

(1) The fugitive emissions monitoring plan as required in §60.5398b(b)(1).

(2) Date of each periodic screening and date that results of the periodic screening were received.

(3) Name of screening operator.

(4) Alternative test method and technology used for screening, as well as the minimum detection threshold for the technology.

(5) Records of calibrations for technology used during the screening if calibration is required by the alternative test method approved in accordance with §60.5398b(d).

(6) Results from periodic screening. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, you must maintain the records in paragraphs (c)(6)(i) through (v) of this section.

(i) The dates of the ground based OGI survey and inspection of covers and closed vent system, as specified in §60.5398b(b)(2).

(ii) Name of operator performing the survey or inspection.

(iii) For surveys and instrument inspections, identification of the monitoring instrument used.

(iv) Records of calibrations for the instrument used during the survey or instrument inspection, as applicable.

(v) For each fugitive emission from a fugitive emissions components affected facility and each leak or defect for each cover and closed vent system inspection, you must maintain the records in paragraphs (c)(6)(v)(A) through (E) of this section.

(A) The location of the fugitive emissions identified using a unique identifier for the source of the emissions and the type of fugitive emissions component.

(B) The location of the leak or defect from a cover or closed vent system using a unique identifier for the source of the leak or defect.

(C) If a defect of a closed vent system, cover, or control device is identified, a description of the defect.

(D) The date of repair for each fugitive emission from a fugitive emissions components affected facility or each leak or defect for each cover and closed vent system.

(E) Number and type of fugitive emission components and identification of each cover or closed vent system placed on delay of repair and an explanation for each delay of repair.

(7) The date the root cause analysis was initiated, and the result of the root cause analysis conducted in accordance with §60.5398b(b)(4)(iv) and (v), as applicable.

(8) Date of implementation of corrective action(s), date of the completion of the corrective action(s), and a description of the corrective action(s) taken in accordance with §60.5398b((b)(4)(iv) and (v), as applicable.

(9) The information in paragraphs (c)(9)(i) through (vi) of this section if you are required to conduct OGI surveys in accordance with §60.5398b(b)(3).

(i) The date of the OGI survey.

(ii) Location of each fugitive emission identified.

(iii) Type of fugitive emissions component for which fugitive emissions were detected.

(iv) The date of first attempt at repair of the fugitive emissions component(s).

(v) The date of successful repair of the fugitive emissions component(s), including the resurvey to verify the repair.

(vi) Identification of each fugitive emissions component placed on delay of repair and an explanation for each delay of repair.

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

(11) All records required by the alternative approved in accordance with §60.5398b(d).

(d) If you comply with the continuous monitoring system requirements of §60.5398b(c), you must submit the information in paragraphs (d)(1) through (6) of this section in the annual report required by §60.5420b(b)(4) through (b)(11).

(1) The start date and end date for each period where the emissions rate determined in accordance with §60.5398b(c)(5) exceeded one of the action levels determined in accordance with §60.5398b(c)(4). Include which action level was exceeded (the rolling 7-day or 90-day average), the numerical value of the action level, and the mass emission rate calculated by the continuous monitoring system in the report.

(2) The date the root cause analysis was initiated, and the result of the root cause analysis conducted in accordance with §60.5398b(c)(6), as applicable.

(3) Date of implementation of corrective action(s), date of the completion of the corrective action(s), and a description of the corrective action(s) taken in accordance with §60.5398b(c)(6), as applicable.

(4) If there are no instances reported under paragraph (d)(1) of this section, report your numerical action levels and the highest rolling 7-day average and highest rolling 90-day average determined by your continuous monitoring system during the reporting period.

(5) The start date for each instance where the 12-month rolling average operational downtime of the system exceeded 10 percent and the value of the 12-month rolling average operational downtime during the period. If there were no instances during the reporting period where the 12-month rolling average operational downtime of the system exceeded 10 percent, report the highest value of the 12-month rolling average operational downtime during the reporting period.

(6) Any additional information regarding the performance of the continuous monitoring system as specified by the Administrator, as part of the alternative test method approval described in §60.5398b(d).

(e) If you comply with the continuous monitoring system requirements of §60.5398b(c), you must maintain the records in paragraphs (e)(1) through (12) of this section.

(1) The fugitives emissions monitoring plan required by §60.5398b(c)(2).

(2) Date of commencement of continuous monitoring with your continuous monitoring system.

(3) The detection level of the continuous monitoring system.

(4) The results of checks for connectivity and power in accordance with §60.5398b(c)(1)(ii).

(5) The beginning and end of each period of operational downtime for the system.

(6) Each rolling 12-month average operational downtime for the system, calculated in accordance with §60.5398b(c)(1)(ii)(D).

(7) The rolling 7-day average and rolling 90-day average action levels for the site determined in accordance with §60.5398b(c)(4).

(8) Each methane mass emission rate reading determined by the system.

(9) Each daily average, 7-day, and 90-day mass emissions rate which was determined in accordance with §60.5398b(c)(5).

(10) The results of each comparison of the emissions rate determined in accordance with §60.5398b(c)(5) to the action level determined in accordance with §60.5398b(c)(4).

(11) The date the root cause analysis was initiated, and the result of the root cause analysis conducted in accordance with §60.5398b(c)(6), as applicable.

(12) Date of implementation of corrective action(s), date of the completion of the corrective action(s), and a description of the corrective action(s) taken in accordance with §60.5398b(c)(6), as applicable.

**§60.5425b What parts of the General Provisions apply to me?**

Table 5 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

**§60.5430b What definitions apply to this subpart?**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of part 60; and the following terms shall have the specific meanings given them.

*Access to electrical power* means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.

*Acid gas* means a gas stream of hydrogen sulfide ($H_2S$) and carbon dioxide ($CO_2$) that has been separated from sour natural gas by a sweetening unit.

*Alaskan North Slope* means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

*API Gravity* means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

*Artificial lift equipment* means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

*Bleed rate* means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

*Capital expenditure* means, as an alternative to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the “CPI-U, U.S. city average, all items” must be used for each CPI value; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

*Centralized production facility* means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

*Centrifugal compressor* means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

*Certifying official* means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities with an affected facility subject to this subpart and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the

proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the CAA or the regulations promulgated thereunder are concerned; or

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

*Closed vent system* means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

*Coil tubing cleanout* means the process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. Coil tubing cleanout includes mechanical methods to remove solids and/or debris from a wellbore.

*Collection system* means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

*Completion combustion device* means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

*Compressor mode* means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, "mode" refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

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

*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.

*Connector* means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

*Continuous bleed* means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

*Crude oil and natural gas source category means:*

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

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

*Custody meter* means the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination.

*Custody meter assembly* means an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter.

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

*Dehydrator* means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or adsorption column (absorber).

*Delineation* well means a well drilled in order to determine the boundary of a field or producing reservoir.

*Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard of this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

*Distance piece* means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

*Double block and bleed system* means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

*Duct work* means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screw or crimping. Hard-piping is not ductwork.

*Emergency shutdown device* means a device which functions exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.

*Equipment*, as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that has the potential to emit methane or VOC and any device or system required by those same standards and requirements of this subpart.

*Field gas* means feedstock gas entering the natural gas processing plant.

*Field gas gathering* means the system used transport field gas from a field to the main pipeline in the area.

*First attempt at repair* means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

*Flare* means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

*Flow line* means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

*Flowback* means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. Screenouts, coil tubing cleanouts, and plug drill-outs are not considered part of the flowback process.

*Fuel gas* means gases that are combusted to derive useful work or heat.

*Fuel gas system* means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

*Fugitive emissions* are defined as any indication of visible emissions observed from a fugitive emissions component using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.

*Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411b, thief hatches or other openings on a storage vessel not subject to §60.5395b, compressors, instruments, meters, and in yard piping.

*Gas to oil ratio* (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

*Hard-piping* means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

*Hydraulic fracturing* means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

*Hydraulic refracturing* means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

*In gas/vapor service* means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

*In heavy liquid service* means that the piece of equipment is not in gas/vapor service or in light liquid service.

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in §60.5402b(d)(2) or §60.5403b.

*In vacuum service* means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

*In wet gas service* means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

*Initial calibration value* as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants means the concentration measured during the initial calibration at the beginning of each day required in §60.5403b, or the most recent calibration if the instrument is recalibrated during the day (*i.e.*, the calibration is adjusted) after a calibration drift assessment.

*Initial flowback stage* means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

*Intermediate hydrocarbon liquid* means any naturally occurring, unrefined petroleum liquid.

*Intermittent vent natural gas-driven pneumatic controller* means a pneumatic controller that is not designed to have a continuous bleed rate but is instead designed to only release natural gas to the atmosphere as part of the actuation cycle.

*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.

*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.

*Liquids dripping* means any visible leakage from the seal, including spraying, misting, clouding, and ice formation.

*Liquids unloading* means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production.

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

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

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under §60.5432b, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

*Major production and processing equipment* means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

*Maximum average daily throughput* means the following:

(1) The earliest calculation of daily average throughput, determined as described in paragraph (2) or (3) of this definition, to a tank battery over the days that production is routed to that tank battery during the 30-day PTE evaluation period employing generally accepted methods specified in §60.5365b(e)(2).

(2) If throughput to the tank battery is measured on a daily basis (*e.g.*, via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to the tank battery during the 30-day evaluation period; or

(3) If throughput to the tank battery is not measured on a daily basis (*e.g.*, via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that tank battery during the 30-day evaluation period, as determined by averaging total throughput to that tank battery over each production period. A production period begins when production begins to be routed to a tank battery and ends either when throughput is routed away from that tank battery or when a loadout occurs from that tank battery, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to the tank battery when calculating maximum average daily throughput for that tank battery.

*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. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

*Natural gas-driven pneumatic controller* means a pneumatic controller powered by pressurized natural gas.

*Natural gas liquids* means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

*Natural gas processing plant (gas plant)* means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

*Natural gas transmission* means the pipelines used for the long-distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

*Nonfractionating plant* means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

*Non-natural gas-driven pneumatic controller* means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

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

*Open-ended valve or line or open-ended vent line* means any valves, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

*Plug drill-out* means the removal of a plug (or plugs) that was used to isolate different sections of the well.

*Pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

*Pressure release* means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

*Pressure vessel* means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

*Process improvement* means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

*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.

*Process unit shutdown* means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

*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.

*Qualified Professional Engineer* means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

*Quarter* means a 3-month period. For purposes of standards for process unit equipment affected facilities at onshore natural gas processing plants, the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

*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.

*Recovered gas* means gas recovered through the separation process during flowback.

*Recovered liquids* means any crude oil, condensate or produced water recovered through the separation process during flowback.

*Reduced emissions completion* means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

*Reduced sulfur compounds* means $H_2S$, carbonyl sulfide (COS), and carbon disulfide ($CS_2$).

*Removed from service* means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with §60.5395b(c)(1).

*Repaired* means the following:

(1) For the purposes of fugitive emissions components affected facilities, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in §60.5397b and resurveyed as specified in §60.5397b(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

(2) For the purposes of process unit equipment affected facilities, that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in §§60.5400b and 60.5401b and is re-monitored as specified in §§60.5400b(b) and §60.5400b(b)(1) or 60.5403b, respectively, to verify that emissions from the equipment are below the applicable leak definition. Pumps in light liquid service subject to §60.5400b(c)(2) or §60.5401b(b)(1)(ii) are not subject to re-monitoring.

*Replacement cost* means the capital needed to purchase all the depreciable components in a facility.

*Returned to service* means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

*Routed to a process or route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

*Salable quality gas* means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

*Screenout* means an attempt to clear proppant from the wellbore to dislodge the proppant out of the well.

*Self-contained pneumatic controller* means a natural gas-driven pneumatic controller that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

*Self-contained wet seal centrifugal compressor* means a wet seal centrifugal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (*i.e.,* degassed emissions are recovered). The de-gas emissions are routed back to suction directly from the degassing/sparging chambers; and the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent.

*Sensor* means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

*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.

*Small well site* means, for purposes of the fugitive emissions standards in §§60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, or natural gas-driven pneumatic controllers.

*Startup of production* means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of §60.5397b, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

*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 §60.5395b(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 §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

*Sulfur production rate* means the rate of liquid sulfur accumulation from the sulfur recovery unit.

*Sulfur recovery unit* means a process device that recovers element sulfur from acid gas.

*Surface site* means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

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

*Tank battery* means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

*Total Reduced Sulfur (TRS)* means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

*Total $SO_2$ equivalents* means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as $SO_2$ to the quantity of $SO_2$ that would be obtained if all reduced sulfur compounds were converted to $SO_2$ (ppmv or kg/dscm (lb/dscf)).

*UIC Class I oilfield disposal well* means a well with a UIC Class I permit that meets the definition in 40 CFR 144.6(a)(2) and receives eligible fluids from oil and natural gas exploration and production operations.

*UIC Class II oilfield disposal well* means a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.

*Underground storage vessel* means a storage vessel stored below ground.

*Well* means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

*Well completion* means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

*Well completion operation* means any well completion with hydraulic fracturing or refracturing occurring at a well completion affected facility.

*Well completion vessel* means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

*Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at §60.5397b, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

*Wellhead* means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

*Wellhead only well site* means, for the purposes of the fugitive emissions standards at §60.5397b, a well site that contains one or more wellheads and no major production and processing equipment.

*Wildcat well* means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

**§60.5432b How do I determine whether a well is a low pressure well using the low pressure well equation?**

(a) To determine that your well is a low pressure well subject to §60.5375b(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in §60.5430b. To determine that the well meets the definition of low pressure well in §60.5430b, you must use the low pressure well equation below:

$$P_L\ (psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L$$

Where:

(1) $P_L$ is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) $P_R$ is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) $L$is the true vertical depth of the well, expressed in feet (ft);

(4) $q_o$ is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) $q_g$ is the flow rate of gas in the well, expressed in cu ft/sec;

(6) $q_w$ is the flow rate of water in the well, expressed in cu ft/sec;

(7) $\rho_o$ is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, $P_{BH}$ (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, $P_R$ (*psia*), in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

(2) Determine the value of the bottom hole temperature, $T_{BH}$ (*F*), based on available information at the well site, or by calculating it using the true vertical depth of the well, *L (ft)*, in the following equation:

$T_{BH}$ (*F*) = (0.014 × *L*) + 79.081

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, $\gamma_{gs}$, using the following equation with: Separator at standard conditions (pressure, $p$ = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, $\gamma_0$; and the gas specific gravity at the separator under standard conditions, $\gamma_{gp}$ = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, $P_{BH}$ (*psia*), determined in (b)(1) of this section; the bottom hole temperature, $T_{BH}$ (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, $\gamma_{gs}$, calculated in (b)(3) of this section; the oil API gravity, $\gamma_o$, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot P_{BH}{}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]$$

**TABLE A—COEFFICIENTS FOR THE CORRELATION FOR $R_S$**

| Constant | $\gamma_{API} \leq 30$ | $\gamma_{API} > 30$ |
|---|---|---|
| C1 | 0.0362 | 0.0178 |
| C2 | 1.0937 | 1.1870 |
| C3 | 25.7240 | 23.931 |

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, $T_{BH}$ (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, $\gamma_{gs}$, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, $\gamma o$, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

**TABLE B—COEFFICIENTS FOR THE CORRELATION FOR $B_O$**

| Constant | $\gamma_{API} \leq 30$ | $\gamma_{API} > 30$ |
|---|---|---|
| C1 | $4.677 \times 10^{-4}$ | $4.670 \times 10^{-4}$ |
| C2 | $1.751 \times 10^{-5}$ | $1.100 \times 10^{-5}$ |
| C3 | $-1.811 \times 10^{-8}$ | $1.337 \times 10^{-9}$ |

(6) Calculate the density of oil at the wellhead,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right)$,

using the following equation with the value of the oil API gravity, $\gamma o$, at the well site:

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

(7) Calculate the density of oil at bottom hole conditions,

$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right)$,

using the following equation with: the dissolved GOR, Rs (scf/ STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/ STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right)$,

calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd}$ = 0.77:

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

(8) Calculate the density of oil in the well,

$\rho_o\left(\frac{lbm}{cu\ ft}\right)$,

using the following equation with the density of oil at the wellhead,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right)$,

calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right)$,

calculated in paragraph (b)(7) of this section:

$$\rho_o\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

(9) Calculate the oil flow rate, $q_o$ (*cu ft/sec*,) using the following equation with: the oil formation volume factor, *Bo* (bbl/ STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/ day):

$$q_o\left(\frac{cu\ ft}{sec}\right) = \mathrm{Qo}\left(\frac{\mathrm{STBO}}{\mathrm{day}}\right) \times \mathrm{Bo}\left(\frac{\mathrm{bbl}}{\mathrm{STBO}}\right) \times 5.614\left(\frac{\mathrm{cu\ ft}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

(10) Calculate the critical pressure, $P_c$ (psia), and critical temperature, $T_c$ (R), using the equations below with: Gas gravity at standard conditions (pressure, $P$ = 14.7 (*psia*), temperature, T = 60 (*F*)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N2} = 0.168225$, $X_{CO2} = 0.013163$, and $X_{H2S} = 0.013680$, respectively:

$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N2} + 440 \cdot X_{CO2} + 606.7 \cdot X_{H2S}$

$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N2} - 88.3 \cdot XCO_2 + 133.3 \cdot X_{H2S}$

(11) Calculate reduced pressure, $P_r$, and reduced temperature, $T_r$, using the following equations with: the bottom hole pressure, $P_{BH}$, as determined in paragraph (b)(1) of this section; the bottom hole temperature, $T_{BH}$ (*F*), as determined in paragraph (b)(2) of this section in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{T_{BH} + 460}{T_c}$$

(12)(i) Calculate the gas compressibility factor, *Z*, using the following equation with the reduced pressure, $P_r$, calculated in paragraph (b)(11) of this section:

$$z = A + \frac{(1 - A)}{e^B} + C \cdot p_r^D$$

(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, $P_r$, and reduced temperature, $T_r$, calculated in paragraph (b)(11) of this section:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

(13) Calculate the gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

using the bottom hole pressure, $P_{BH}$ *(psia)*, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, $T_{BH}$ *(F)*, as determined in paragraph (b)(2) of this section:

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}}()$$

(14) Calculate the gas flow rate,

$$q_g\left(\frac{cu\ ft}{sec}\right),$$

using the following equation with: the value of gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/ day); the estimated oil production rate, Qo (STBO/ day); and the dissolved GOR, Rs (scf/ STBO), as calculated in paragraph (b)(4) of this section:

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

(15) Calculate the flow rate of water in the well, $q_w$ (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w\left(\frac{cf}{sec}\right) = \mathrm{Qw}\left(\frac{\mathrm{bbl}}{\mathrm{day}}\right) \times 5.614\left(\frac{\mathrm{cf}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

**§§60.5433b-60.5439b [Reserved]**

**Table 1 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites, Centralized Production Facilities, and Compressor Stations Subject to AVO Inspections with Quarterly OGI or EPA Method 21 Monitoring**

| **Minimum Screening Frequency** | **Minimum Detection Threshold of Screening Technology*** |
|---|---|
| Quarterly + Annual OGI | ≤1 kg/hr |
| Bimonthly | ≤2 kg/hr |

| | |
|---|---|
| Bimonthly + Annual OGI | ≤10 kg/hr |
| Monthly | ≤4 kg/hr |
| Monthly + Annual OGI | ≤30 kg/hr |

*Based on a probability of detection of 90%

**Table 2 to Subpart OOOOb of Part 60—Alternative Technology Periodic Screening Frequency at Well Sites and Centralized Production Facilities Subject to AVO Inspections and/or Semiannual OGI or EPA Method 21 Monitoring**

| **Minimum Screening Frequency** | **Minimum Detection Threshold of Screening Technology*** |
|---|---|
| Semiannual | ≤1 kg/hr |
| Triannual | ≤2 kg/hr |
| Triannual + Annual OGI | ≤5 kg/hr |
| Quarterly + Annual OGI | ≤15 kg/hr |
| Monthly + Annual OGI | ≤30 kg/hr |

*Based on a probability of detection of 90%

**Table 3 to Subpart OOOOb of Part 60—Required Minimum Initial $SO_2$ Emission Reduction Efficiency ($Z_i$)**

| **$H_2S$ content of acid gas (Y), %** | **Sulfur feed rate (X), LT/D** | | | |
|---|---|---|---|---|
| | **2.0 < X < 5.0** | **5.0 < X < 15.0** | **15.0 < X < 300.0** | **X > 300.0** |
| Y > 50 | 79.0 | $88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller. | | |
| 20 < Y < 50 | 79.0 | $88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller | | 97.9 |
| 10 < Y < 20 | 79.0 | $88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller | 93.5 | 93.5 |
| **Y < 10** | **79.0** | **79.0** | **79.0** | **79.0** |

**Table 4 to Subpart OOOOb of Part 60—Required Minimum $SO_2$ Emission Reduction Efficiency ($Z_c$)**

| **$H_2S$ content of acid gas (Y), %** | **Sulfur feed rate (X), LT/D** | | | |
|---|---|---|---|---|
| | **2.0 < X < 5.0** | **5.0 < X < 15.0** | **15.0 < X < 300.0** | **X > 300.0** |

| | | | | |
|---|---|---|---|---|
| Y > 50 | 74.0 | $85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller. | | |
| 20 < Y < 50 | 74.0 | $85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller | | 97.5 |
| 10 < Y < 20 | 74.0 | $85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller | 90.8 | 90.8 |
| Y < 10 | 74.0 | 74.0 | 74.0 | 74.0 |

X = The sulfur feed rate from the sweetening unit (*i.e.*, the $H_2S$ in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent $H_2S$ (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide ($SO_2$) emission reduction efficiency, expressed as percent carried to one decimal place. $Z_i$ refers to the reduction efficiency required at the initial performance test. $Z_c$ refers to the reduction efficiency required on a continuous basis after compliance with $Z_i$ has been demonstrated.

As stated in §60.5425b, you must comply with the following applicable General Provisions:

**Table 5 to Subpart OOOOb of Part 60—Applicability of General Provisions to Subpart OOOOb**

| General provisions citation | Subject of citation | Applies to subpart? | Explanation |
|---|---|---|---|
| §60.1 | General applicability of the General Provisions | Yes | |
| §60.2 | Definitions | Yes | Additional terms defined in §60.5430b. |
| §60.3 | Units and abbreviations | Yes | |

| | | | |
|---|---|---|---|
| §60.4 | Address | Yes | |
| §60.5 | Determination of construction or modification | Yes | |
| §60.6 | Review of plans | Yes | |
| §60.7 | Notification and record keeping | Yes | Except that §60.7 only applies as specified in §§60.5417b(c) and 60.5420b(a). |
| §60.8 | Performance tests | Yes | Except that the format and submittal of performance test reports is described in §60.5420b(b) and (d). Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s). |
| §60.9 | Availability of information | Yes | |
| §60.10 | State authority | Yes | |
| §60.11 | Compliance with standards and maintenance requirements | No | Requirements are specified in subpart OOOOb. |
| §60.12 | Circumvention | Yes | |
| §60.13 | Monitoring requirements | Yes | |
| §60.14 | Modification | Yes | To the extent any provision in §60.14 conflicts with specific provisions in subpart OOOOb, it is superseded by subpart OOOOb provisions. |
| §60.15 | Reconstruction | Yes | Except that §60.15(d) does not apply to wells (*i.e.*, well completions, well liquids unloading, oil wells with associated gas), pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or fugitive emissions components affected facilities. |
| §60.16 | Priority list | Yes | |
| §60.17 | Incorporations by reference | Yes | |
| §60.18 | General control device and work | Yes | |

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|---|---|---|---|
| | practice requirements | | |
| §60.19 | General notification and reporting requirement | Yes | |