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

SOURCE: 81 FR 35898, June 3, 2016, unless otherwise noted.

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§60.5360a What is the purpose of this subpart?

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

(b) [Reserved]

[85 FR 57070, Sept. 14, 2020, as amended at 85 FR 57438, Sept. 15, 2020]

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§60.5365a Am I subject to this subpart?

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

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of §60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to §60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in §60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

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

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

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

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

(e) Each storage vessel affected facility, which is a single storage vessel as specified in paragraph (e)(1), (2), or (3) of this section.

(1) A single storage vessel that commenced construction, reconstruction, or modification after September 18, 2015, and on or before November 16, 2020, is a storage vessel affected facility if its potential for VOC emissions is equal to or greater than 6 tons per year (tpy) as determined according to this paragraph (e)(1). The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput (as defined in §60.5430a) determined for a 30-day period prior to the applicable emission determination deadline specified in paragraphs (e)(2)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv). The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.

(2) Except as specified in paragraph (e)(3) of this section, a single storage vessel that commenced construction, reconstruction or modification after November 16, 2020, is a storage vessel affected facility if the potential for VOC emissions is equal to or greater than 6 tpy as determined according to paragraph (e)(2)(i) or (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The determination may take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority. The potential for VOC emissions is calculated on an individual storage vessel basis and is not averaged across the number of storage vessels at the site.

(i) For each storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC emissions must be calculated for each individual storage vessel using a generally accepted model or calculation methodology, based on the maximum average daily throughput, as defined in §60.5430a, determined for a 30-day period of production.

(ii) For each storage vessel located at a compressor station or onshore natural gas processing plant, you must determine the potential for VOC emissions prior to startup of the compressor station or onshore natural gas processing plant using either method described in paragraph (e)(2)(ii)(A) or (B) of this section.

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

(B) Determine the potential for VOC emissions using a generally accepted model or calculation methodology and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.,* volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum average daily throughput for the storage vessel.

(3) If a storage vessel battery, which consists of two or more storage vessels, meets all of the design and operational criteria specified in paragraphs (e)(3)(i) through (iv) of this section through legally and practicably enforceable standards in a permit or other requirement established under Federal, state, local, or tribal authority, then each storage vessel in such storage vessel battery is a storage vessel affected facility.

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

(ii) The storage vessels must be equipped with a closed vent system that is designed, operated, and maintained to route the vapors back to the process or to a control device;

(iii) The vapors collected in paragraph (e)(3)(i) of this section must be routed back to the process or to a control device that reduces VOC emissions by at least 95.0 percent; and

(iv) The VOC emissions, averaged across the number of storage vessels in the battery meeting all of the criteria of paragraphs (e)(3)(i) through (iii) of this section, are equal to or greater than 6 tpy.

(v) If a storage vessel battery meeting all of the criteria specified in paragraphs (e)(3)(i) through (iii) of this section through legally and practicably enforceable standards in a permit or other requirements established under Federal, state, local, or tribal authority, emits less than 6 tpy of VOC emissions averaged across the number of storage vessels in the battery, none of the storage vessels in the battery are storage vessel affected facilities.

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

(5) For storage vessels not subject to a legally and 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 VRU designed and operated as specified in this section is not required to be included in the determination of potential for VOC emissions for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(5)(i) through (iv) of this section.

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

(ii) You meet the closed vent system requirements specified in §60.5411a(c) and (d).

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

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

(6) The requirements of this paragraph (e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that applied to the storage vessel affected facility being replaced.

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

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

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

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that commenced construction, modification, or reconstruction after September 18, 2015, and on or before November 16, 2020, and sweetening units that commence construction, modification, or reconstruction after November 16, 2020.

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

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

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

(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 §§60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year 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) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a “modification” to a well site occurs when:

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

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

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

(4) For purposes of §60.5397a, a “modification” to an existing source separate tank battery surface site occurs when:

(i) Any of the actions in paragraphs (i)(3)(i) through (iii) of this section occurs at an existing source separate tank battery surface site;

(ii) A well sending production to an existing source separate tank battery site is modified, as defined in paragraphs (i)(3)(i) through (iii) of this section; or

(iii) A well site subject to the requirements in §60.5397a removes all major production and processing equipment, as defined in §60.5430a, such that it becomes a wellhead only well site and sends production to an existing source separate tank battery surface site.

(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. For purposes of §60.5397a, a “modification” to a compressor station occurs when:

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

(2) 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 §60.5397a.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 85 FR 57438, Sept. 15, 2020]

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§60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(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.

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

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

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in §60.5430a, follow the requirements specified in paragraphs (a)(1)(i) 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 in paragraph (a)(3) 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 facility or well pad that services the well affected facility during well completions. The separator must be available and ready for use to comply with paragraph (a)(1)(ii) of this section during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(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 §60.5375a(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 §60.5420a(b)(2) and maintain the records in §60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in §60.5375a(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.

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

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

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

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

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420a(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 either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) 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. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

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

(g) For each well 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 §60.5420a(c)(1)(vi).

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

[81 FR 35898, June 3, 2016, as amended at 85 FR 57070, Sept. 14, 2020; 85 FR 57439, Sept. 15, 2020]

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

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

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

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

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (3), and the recordkeeping as required by §60.5420a(c)(2), (6) through (11), and (17), as applicable.

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

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

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section, or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, August 2, 2016, or the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

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

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (4) and the recordkeeping as required by §60.5420a(c)(3), (6) through (9), and (17), as applicable.

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

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

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420a(c)(4)(iii).

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

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

(f) You must perform the reporting as required by §60.5420a(b)(1) and (5) and the recordkeeping as required by §60.5420a(c)(4).

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

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

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(b) For each pneumatic pump affected facility at a well site you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4), and (5) of this section.

(1)-(2) [Reserved]

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section. For the purposes of this section, boilers and process heaters are not considered control devices. In addition, routing emissions from pneumatic pump discharges to boilers and process heaters is not considered routing to a process.

(i) Submit a certification in accordance with §60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in §60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(3)(i) of this section and must submit the information in §60.5420a(b)(8)(ii) in your next annual report and maintain the records in §60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95-percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95-percent reduction, you must submit the information specified in §60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in §60.5420a(c)(16)(iii).

(5) If an owner or operator determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraphs (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer or in-house engineer, shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(iii) The assessment of technical infeasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device or process, pressure losses and differentials in the closed vent system, and the ability of the control device or process to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer or in-house engineer who signs the certification in accordance with paragraph (b)(5)(ii) of this section.

(iv) The owner or operator shall maintain the records specified in §60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in the next annual report in accordance with §60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §§60.5411a(d) and (e), 60.5415a(b)(3), and 60.5416a(d).

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410a(e).

(e) You must perform the reporting as required by §60.5420a(b)(1) and (8) and the recordkeeping as required by §60.5420a(c)(6) through (10), (16), and (17), as applicable.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57070, Sept. 14, 2020; 85 FR 57439, Sept. 15, 2020]

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§60.5395a What VOC standards apply to storage vessel affected facilities?

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

(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 in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with §60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in §60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You 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 monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d), and you must route emissions to a control device that meets the conditions specified in §60.5412a(c) or (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) Requirements for storage vessel affected facilities that are removed from service or returned to service. If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

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

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

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

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

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

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

(1) You must demonstrate initial compliance with standards as required by §60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415a(e)(3).

(3) You must perform the required reporting as required by §60.5420a(b)(1) and (6) and the recordkeeping as required by §60.5420a(c)(5) through (8), (12) through (14), and (17), 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.

[77 FR 49542, Aug. 16, 2012, as amended at 85 FR 57440, Sept. 15, 2020]

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

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

(a) You must comply with paragraph (a)(1) of this section, unless your affected facility under §60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section. If your affected facility under §60.5365a(i) (*i.e.,* the collection of fugitive emissions components at a well site) meets the conditions specified in either paragraph (a)(1)(i) or (ii) of this section, you must comply with either paragraph (a)(1) or (2) of this section.

(1) You must monitor all fugitive emission components, as defined in §60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.

(i) *First 30-day production.* For the collection of fugitive emissions components at a well site, where the total production of the well site is at or below 15 barrels of oil equivalent (boe) per day for the first 30 days of production, according to §60.5415a(j), you must comply with the provisions of either paragraph (a)(1) or (2) of this section. Except as provided in this paragraph (a)(1)(i), the calculation must be performed within 45 days of the end of the first 30 days of production. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000. For well sites that commenced construction, reconstruction, or modification between October 15, 2019, and November 16, 2020, the owner or operator may use the records of the first 30 days of production after becoming subject to this subpart, if available, to determine if the total well site production is at or below 15 boe per day, provided this determination is completed by December 14, 2020.

(ii) *Well site production decline.* For the collection of fugitive emissions components at a well site, where, at any time, the total production of the well site is at or below 15 boe per day based on a rolling 12-month average, you must comply with the provisions of either paragraph (a)(1) or (2) of this section. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(2) You must maintain the total production for the well site at or below 15 boe per day based on a rolling 12-month average, according to §§60.5410a(k) and 60.5415a(i), comply with the reporting requirements in §60.5420a(b)(7)(i)(C), and the recordkeeping requirements in §60.5420a(c)(15)(ii), until such time that you perform any of the actions in paragraphs (a)(2)(i) through (v) of this section. If any of the actions listed in paragraphs (a)(2)(i) through (v) of this section occur, you must comply with paragraph (a)(3) of this section.

(i) A new well is drilled at the well site;

(ii) A well at the well site is hydraulically fractured;

(iii) A well at the well site is hydraulically refractured;

(iv) A well at the well site is stimulated in any manner for the purpose of increasing production, including well workovers; or

(v) A well at the well site is shut-in for the purpose of increasing production from the well.

(3) You must determine the total production for the well site for the first 30 days after any of the actions listed in paragraphs (a)(2)(i) through (v) of this section is completed, according to §60.5415a(j), comply with paragraph (a)(3)(i) or (ii) of this section, the reporting requirements in §60.5420a(b)(7)(i)(C), and the recordkeeping requirements in §60.5420a(c)(15)(iii).

(i) If the total production for the well site is at or below 15 boe per day for the first 30 days after the action is completed, according to §60.5415a(j), you must either continue to comply with paragraph (a)(2) of this section or comply with paragraph (a)(1) of this section.

(ii) If the total production for the well site is greater than 15 boe per day for the first 30 days after the action is completed, according to §60.5415a(j), you must comply with paragraph (a)(1) of this section and conduct an initial monitoring survey for the collection of fugitive emissions components at the well site in accordance with the same schedule as for modified well sites as specified in §60.5397a(f)(1).

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans 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 meeting the requirements in 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, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

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

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/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 at 40 CFR part 60, appendix A-7.* 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 at 40 CFR part 60, appendix A-7, 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)(3) of this section, and the written plan for fugitive emissions components designated as unsafe-to-monitor in accordance with paragraph (g)(4) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in §60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 90 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 90 days of the startup of production for each collection of fugitive emissions components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in §60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is latest.

(2) You must conduct an initial monitoring survey within 90 days of the startup of a new compressor station for each collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a compressor station, the initial monitoring survey must be conducted within 90 days of the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a new compressor station located on the Alaskan North Slope that starts up between September and March, you must conduct an initial monitoring survey within 6 months of the startup date for new compressor stations, within 6 months of the modification, or by the following June 30, whichever is latest.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) through (5) of this section.

(1) Except as provided in this paragraph (g)(1), a monitoring survey of each collection of fugitive emissions components at a well site must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(2) Except as provided in this paragraph (g)(2), a monitoring survey of the collection of fugitive emissions components at a compressor station must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart and no more than 7 months apart. A monitoring survey of the collection of fugitive emissions components at a compressor station located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(3) 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)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of 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.

(4) 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)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of 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.

(5) You are no longer required to comply with the requirements of paragraph (g)(1) of this section when the owner or operator removes all major production and processing equipment, as defined in §60.5430a, such that the well site becomes a wellhead only well site. If any major production and processing equipment is subsequently added to the well site, then the owner or operator must comply with the requirements in paragraphs (f)(1) and (g)(1) of this section.

(h) Each identified source of fugitive emissions shall be repaired, as defined in §60.5430a, in accordance with paragraphs (h)(1) and (2) of this section.

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

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

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

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

(i) The operator may resurvey the fugitive emissions components to verify repair using either Method 21 of appendix A-7 of this part or optical gas imaging.

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

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

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

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

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

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

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

(i) Records for each monitoring survey shall be maintained as specified §60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in §60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018; 85 FR 57070, Sept. 14, 2020; 85 FR 57440, Sept. 15, 2020]

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

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under §60.5375a, §60.5385a, or §60.5397a, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with §60.5375a, §60.5385a, or §60.5397a. The authority to approve an alternative means of emission limitation is retained by the Administrator and shall not be delegated to States under section 111(c) of the Clean Air Act (CAA).

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

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

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

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

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

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

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

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

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

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

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

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

[85 FR 57442, Sept. 15, 2020]

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§60.5399a What alternative fugitive emissions standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station: Equivalency with state, local, and tribal programs?

This section provides alternative fugitive emissions standards based on programs under state, local, or tribal authorities for the collection of fugitive emissions components, as defined in §60.5430a, located at well sites and compressor stations. Paragraphs (a) through (e) of this section outline the procedure for submittal and approval of alternative fugitive emissions standards. Paragraphs (f) through (n) provide approved alternative fugitive emissions standards. The terms “fugitive emissions components” and “repaired” are defined in §60.5430a and must be applied to the alternative fugitive emissions standards in this section. The requirements for a monitoring plan as specified in §60.5397a(c) and (d) apply to the alternative fugitive emissions standards in this section.

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

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

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

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

(2) The monitoring frequency;

(3) The fugitive emissions definition;

(4) The repair requirements; and

(5) The recordkeeping and reporting requirements.

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

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

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

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

(2) An owner or operator implementing one of the alternative fugitive emissions standards must submit the reports specified in §60.5420a(b)(7)(iii). An owner or operator must also maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(f) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of California.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a well site or a compressor station in the State of California may elect to reduce VOC emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, sections 95665-95667, effective January 1, 2020, as an alternative to complying with the requirements in §60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i). The information specified in §60.5420a(b)(7)(iii)(A) and the information specified in either §60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in §60.5397a(j).

(g) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site or a compressor station in the State of Colorado.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a well site or a compressor station in the State of Colorado may elect to comply with the monitoring, repair, and recordkeeping requirements in Colorado Regulation 7, Part D, section I.L or II.E, effective February 14, 2020, for well sites and compressor stations, as an alternative to complying with the requirements in §60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). Monitoring must be conducted on at least a semiannual basis for well sites and compressor stations.

If using the alternative in this paragraph (g), the information specified in §60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in §60.5397a(j).

(h) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a well site in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permits 12.1, Section C.5 and 12.2, Section C.5, effective April 14, 2014, as an alternative to complying with the requirements in §60.5397a(f)(1), (g)(1), (3), and (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in §60.5420a(b)(7)(iii)(A) and the information specified in either §60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in §60.5397a(j).

(i) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Ohio.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a compressor station in the State of Ohio may elect to comply with the monitoring, repair, and recordkeeping requirements in Ohio General Permit 18.1, effective February 7, 2017, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods cannot be applied. The information specified in §60.5420a(b)(7)(iii)(A) and the information specified in either §60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in §60.5397a(j).

(j) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a well site in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5A, section G, effective August 8, 2018, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). The information specified in §60.5420a(b)(7)(iii)(A) and the information specified in either §60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in §60.5397a(j).

(k) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Pennsylvania.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a compressor station in the State of Pennsylvania may elect to comply with the monitoring, repair, and recordkeeping requirements in Pennsylvania General Permit 5, section G, effective August 8, 2018, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is an optical gas imaging or a Method 21 instrument (see appendix A-7 of this part). The information specified in §60.5420a(b)(7)(iii)(A) and the information specified in either §60.5420a(b)(7)(iii)(B) or (C) may be provided as an alternative to the requirements in §60.5397a(j).

(l) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a well site in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the requirement in this paragraph (l), the information specified in §60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in §60.5397a(j).

(m) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a compressor station in the State of Texas.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, located at a compressor in the State of Texas may elect to comply with the monitoring, repair, and recordkeeping requirements in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, section (e)(6), effective November 8, 2012, or at 30 Texas Administrative Code section 116.620, effective September 4, 2000, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i), provided the monitoring instrument used is optical gas imaging or a Method 21 instrument (see appendix A-7 of this part) with a leak definition and reading of 500 ppm or greater. Monitoring must be conducted on at least a semiannual basis and skip periods may not be applied. If using the alternative in this paragraph (m), the information specified in §60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in §60.5397a(j).

(n) *Alternative fugitive emissions requirements for the collection of fugitive emissions components located at a well site in the State of Utah.* An affected facility, which is the collection of fugitive emissions components, as defined in §60.5430a, and is required to control emissions in accordance with Utah Administrative Code R307-506 and R307-507, located at a well site in the State of Utah may elect to comply with the monitoring, repair, and recordkeeping requirements in the Utah Administrative Code R307-509, effective March 2, 2018, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i). If using the alternative in this paragraph (n), the information specified in §60.5420a(b)(7)(iii)(A) and (C) must be provided in lieu of the requirements in §60.5397a(j).

[85 FR 57443, Sept. 15, 2020]

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

This section applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

(a) You must comply with the requirements of §§60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a, as soon as practicable but no later than 180 days after the initial startup of the process unit.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

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

(d) You must comply with the provisions of §60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a except as provided in §§60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57445, Sept. 15, 2020]

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

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

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §§60.5400a(c) and in paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), and 60.482-11a(a) and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °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).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[77 FR 49542, Aug. 16, 2012, as amended at 85 FR 57445, Sept. 15, 2020]

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

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

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

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

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

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

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

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

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020]

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§60.5405a 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 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

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§60.5406a 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 §60.5405a(a) and (b) as follows:

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

$$X = KQ_aY$$

Where:

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

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

Y = average 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)).

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

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

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

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

(3) You must use the Tutwiler procedure in §60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

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

(c) You must determine compliance with the SO_2 standards in §60.5405a(a) or (b) as follows:

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

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

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

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

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

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

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

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or 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 1.333×10^{-3} to convert the results to sulfur equivalent.

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

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

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

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

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

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

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

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

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

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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.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57445, Sept. 15, 2020]

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§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top 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 starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

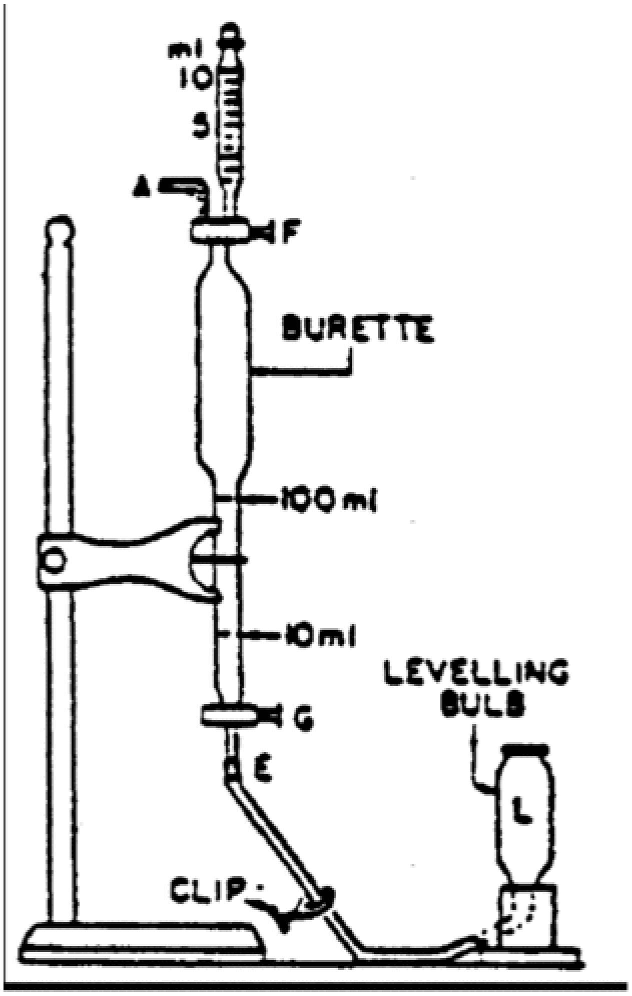

Figure 1. Tutwiler burette (lettered items mentioned in text).

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

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (k) of this section. Except as otherwise provided in this section, the initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than 1 full year.

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

(1) You must submit the notification required in §60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420a(c)(1)(i) through (iv) and must maintain the record in §60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both §60.5375a(a)(1) and (3), as an alternative to retaining the records specified in §60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating 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.

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

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b) that is connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(b).

(4) You must conduct the initial inspections required in §60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417a(a) through (g), as applicable.

(6) [Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with §60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since initial startup, since August 2, 2016, or since the last rod packing replacement, whichever is latest.

(2) If complying with §60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in §60.5420a(c)(3) for each reciprocating compressor affected facility.

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

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in §60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in §60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with §60.5393a(b)(1) or (2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(d) and (e).

(3) If you own or operate a pneumatic pump affected facility located at a well site and there is no control device or process available on site, you must submit the certification in §60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility located at a well site, and you are unable to route to an existing control device or to a process due to technical infeasibility, you must submit the certification in §60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility located at a well site and you reduce emissions in accordance with §60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(d) and (e).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in §60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in §60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

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

(g) For sweetening unit affected facilities, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in §60.5405a(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities.

(h) For each storage vessel affected facility you must comply with paragraphs (h)(1) through (6) of this section. Except as otherwise provided in this paragraph (h), you must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365a(e).

(2) You must reduce VOC emissions in accordance with §60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d) to a control device that meets the conditions specified in §60.5412a(d) within 60 days after startup for storage vessels constructed, modified, or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified, or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in §60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112(b)(a)(1) or (2) in accordance with §60.5395a(b)(2) with the initial annual report specified in §60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in §60.5397a(b), (c), and (d).

(2) You must conduct an initial monitoring survey as required in §60.5397a(f).

(3) You must maintain the records specified in §60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in §60.5420a(b)(1) and (7).

(k) To demonstrate initial compliance with the requirement to maintain the total well site production at or below 15 boe per day based on a rolling 12-month average, as specified in §60.5397a(a)(2), you must comply with paragraphs (k)(1) through (3) of this section.

(1) You must demonstrate that the total daily combined oil and natural gas production for all wells at the well site is at or below 15 boe per day, based on a 12-month average from the previous 12 months of operation, according to paragraphs (k)(1)(i) through (iii) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (k)(1)(iii) of this section must be at or below 15 boe per day.

(i) Determine the daily combined oil and natural gas production for each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(ii) Sum the daily production for each individual well at the well site to determine the total well site production and divide by the number of days in the month. This is the average daily total well site production for the month.

(iii) Use the result determined in paragraph (k)(1)(ii) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(2) You must maintain records as specified in §60.5420a(c)(15)(ii).

(3) You must submit compliance information in the initial and subsequent annual reports as specified in §60.5420a(b)(7)(i)(C) and (b)(7)(iv).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57071, Sept. 14, 2020; 85 FR 57445, Sept. 15, 2020]

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§60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels.

(a) Closed vent system requirements for reciprocating compressors and centrifugal compressor wet seal degassing systems.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process. You must design the closed vent system to route all gases, vapors, and fumes emitted from the centrifugal compressor wet seal fluid degassing system to a process or a control device that meets the requirements specified in §60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel affected facility to a control device that meets the requirements specified in §60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in §60.5416a(c).

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

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

(2) [Reserved]

(e) Closed vent system requirements for pneumatic pump affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the pneumatic pump to a control device or a process.

(2) You must design and operate a closed vent system with no detectable emissions, as demonstrated by §60.5416a(b), olfactory, visual, and auditory inspections or optical gas imaging inspections as specified in §60.5416a(d).

(3) You must meet the requirements specified in paragraphs (e)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (e)(3)(ii) of this section, you must comply with either paragraph (e)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (e)(3)(i) of this section.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017; 85 FR 57446, Sept. 15, 2020]

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

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under

§60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

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

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

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

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under §60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417a(a) through (g), you must demonstrate compliance according to the requirements of §60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) 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.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) 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).

(iv) 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).

(v) 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.

(vi) 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.

(d) Each control device used to meet the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section. If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

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

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) You must introduce the vent stream with the primary fuel or use the vent stream as the primary fuel in a boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57447, Sept. 15, 2020]

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

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412a(a)(1) or (2) or (d)(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 storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have 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 §60.5420(b)(9) 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 §60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) 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 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), 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, 2.494×10^{-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 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:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

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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 use Method 25A of appendix A-7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A-6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

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Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with §60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with §60.5417a(f) and continuously monitor the temperature as required by §60.5417a(d).

(c) *Control device design analysis to meet the requirements of §60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph (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 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) 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 EPA Method 3C tests and EPA 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 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as propane) measurement range may be used.

(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:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

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

(12) The owner or operator of a combustion control device model tested under this paragraph (d)(12) must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section for each test run in the test report required by this section in accordance with §60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS), Room 521; 109 T.W. Alexander Drive; Research Triangle Park, NC 27711. The same file with the CBI omitted must be submitted to *Oil__and__Gas__PT@EPA.GOV.*

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (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 (8) of this section, maintaining the records specified in §60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in §60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(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.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57071, Sept. 14, 2020; 85 FR 57447, Sept. 15, 2020]

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

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

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

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417a(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, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413a(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in §60.5370a(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 §60.5370a(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 (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by §60.5420a(b)(1), (3), and (8) and maintain the records as specified in §60.5420a(c)(2), (6) through (11), (16), and (17), as applicable.

(c) For each reciprocating compressor affected facility complying with §60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with §60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, since August 2, 2016, or since the date of the most recent reciprocating compressor rod packing replacement, whichever is latest.

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (4) and maintain records as required in §60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in §60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (5).

(3) You must maintain records as required in §60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416a(c) for each cover and closed vent system.

(B) You must comply with §60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411a(c)(2) and (3).

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

(g) For each sweetening unit affected facility, you must demonstrate continuous compliance with the standards for SO_2 specified in §60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in §60.5397a(a)(1) according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in §60.5397a(g).

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

(3) You must maintain records as specified in §60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5420a(b)(1) and (7).

(i) For each collection of fugitive emissions components at a well site complying with §60.5397a(a)(2), you must demonstrate continuous compliance according to paragraphs (i)(1) through (4) of this section. You must perform the calculations shown in paragraphs (i)(1) through (4) of this section within 45 days of the end of each month. The rolling 12-month average of the total well site production determined according to paragraph (i)(4) of this section must be at or below 15 boe per day.

(1) Begin with the most recent 12-month average.

(2) Determine the daily combined oil and natural gas production of each individual well at the well site for the month. To convert gas production to equivalent barrels of oil, divide the cubic feet of gas produced by 6,000.

(3) Sum the daily production for each individual well at the well site and divide by the number of days in the month. This is the average daily total well site production for the month.

(4) Use the result determined in paragraph (i)(3) of this section and average with the daily total well site production values determined for each of the preceding 11 months to calculate the rolling 12-month average of the total well site production.

(j) To demonstrate that the well site produced at or below 15 boe per day for the first 30 days after startup of production as specified in §60.5397a(3), you must calculate the daily production for each individual well at the well site during the first 30 days of production after completing any action listed in §60.5397a(a)(2)(i) through (v) and sum the individual well production values to obtain the total well site production. The calculation must be performed within 45 days of the end of the first 30 days of production after completing any action listed in §60.5397a(a)(2)(i) through (v). To convert gas production to equivalent barrels of oil, divide cubic feet of gas produced by 6,000.

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§60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities, you must comply with the applicable requirements of paragraphs (a) through (d) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(4) For each bypass device, except as provided for in §60.5411a(a)(3)(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 steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420a(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraph (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in §60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system and cover as specified in paragraphs (c)(1) and (2) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) *Closed vent system inspections.* For each closed vent system, you must conduct an inspection as specified in paragraphs (c)(1)(i) through (iii) or paragraph (c)(1)(iv) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in §60.5397a(g)(1).

(2) *Cover inspections.* For each cover, you must conduct inspections as specified in paragraphs (c)(2)(i) through (iii) or paragraph (c)(2)(iv) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive emissions components located at the same type of site, as specified in §60.5397a(g)(1).

(3) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible 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 to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(d) *Closed vent system inspections for pneumatic pump affected facilities.* If you install a control device or route emissions to a process, you must comply with the inspection and recordkeeping requirements for each closed vent system as specified in paragraph (d)(1) of this section. You must also comply with the requirements of paragraphs (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection as specified in paragraphs (d)(1)(i) through (iii), paragraph (d)(1)(iv), or paragraph (d)(1)(v) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct olfactory, visual, and auditory inspections at least once every calendar month for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(iv) Conduct optical gas imaging inspections for any visible emissions at the same frequency as the frequency for the collection of fugitive components located at the same type of site, as specified in §60.5397a(g)(1).

(v) Conduct inspections as specified in paragraphs (a)(1) and (2) of this section.

(2) [Reserved]

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§60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel affected facility or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device or control device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (4) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in 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 in 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 a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413a(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.

(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 flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °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.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in §60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of §60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(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.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(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 §60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412a(a)(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 §60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412a(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 given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to §60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under §60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413a(d)(2) through (10), which meets the criteria in §60.5413a(d)(11), the reporting requirement in §60.5413a(d)(12), and meet the continuous compliance requirement in §60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57449, Sept. 15, 2020]

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

(a) *Notifications.* You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit, you must submit the notifications required in §§60.7(a)(1), (3), and (4) and 60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §§60.7(a)(1), (3), and (4) and 60.15(d).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(3) An owner or operator electing to comply with the provisions of §60.5399a shall notify the Administrator of the alternative fugitive emissions standard selected within the annual report, as specified in paragraph (b)(7) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section is required for all reports.

(i) The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility that is subject to §60.5375a(a) or (f), the records of each well completion operation conducted during the reporting period, including the information specified in paragraphs (b)(2)(i) through (xiv) of this section, if applicable. In lieu of submitting the records specified in paragraphs (b)(2)(i) through (xiv) of this section, the owner or operator may submit a list of each well completion with hydraulic fracturing completed during the reporting period, and the digital photograph required by paragraph (c)(1)(v) of this section for each well completion. For each well affected facility that routes flowback entirely through one or more production separators, only the records specified in paragraphs (b)(2)(i) through (iv) and (vi) of this section are required to be reported. For periods where salable gas is unable to be separated, the records specified in paragraphs (b)(2)(iv) and (viii) through (xii) of this section must also be reported, as applicable. For each well affected facility that is subject to §60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section is required to be reported.

(i) Well Completion ID.

(ii) Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983.

(iii) U.S. Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing or identification that the well immediately starts production.

(v) The date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii).

(vi) The date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production.

(vii) The duration (in hours) of flowback.

(viii) The duration (in hours) of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(ix) The duration (in hours) of combustion.

(x) The duration (in hours) of venting.

(xi) The specific reasons for venting in lieu of capture or combustion.

(xii) For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(xiii) For each well affected facility subject to §60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined §60.5430a)) and supporting inputs and calculations, if applicable.

(xiv) For each well affected facility for which you claim an exception under §60.5375a(a)(3), the specific exception claimed and reasons why the well meets the claimed exception.

(xv) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, the supporting analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (v) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified, or reconstructed during the reporting period.

(ii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(2) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) If required to comply with §60.5380a(a)(2), the information in paragraphs (b)(3)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under §60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, date of repair or the date of anticipated repair if the repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of §60.5416a(a)(4).

(iv) If complying with §60.5380a(a)(1) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and (e), the information in paragraphs (b)(3)(iv)(A) through (D) of this section.

(A) Identification of the compressor with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(v) If complying with §60.5380a(a)(1) with a control device not tested under §60.5413a(d), identification of the compressor with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since August 2, 2016, or since the previous reciprocating compressor rod packing replacement, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of this section, the date and time the deviation began, duration of the deviation and a description of the deviation.

(iii) If required to comply with §60.5385a(a)(3), the information in paragraphs (b)(4)(iii)(A) through (C) of this section.

(A) Dates of each inspection required under §60.5416a(a) and (b);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of §60.5416a(a)(4).

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified, or reconstructed during the reporting period, including the month and year of installation, reconstruction or modification and identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section.

(ii) If applicable, reason why the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required.

(iii) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (ix) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification, or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to §60.5365a(e)(1) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

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

(iv) A statement that you have met the requirements specified in §60.5410a(h)(2) and (3).

(v) For each storage vessel constructed, modified, reconstructed, or returned to service during the reporting period complying with §60.5395a(a)(2) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and (e), the information in paragraphs (b)(6)(v)(A) through (D) of this section.

(A) Identification of the storage vessel with the control device.

(B) Make, model, and date of purchase of the control device.

(C) For each instance where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, include the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(D) For each visible emissions test following return to operation from a maintenance or repair activity, the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(vi) If complying with §60.5395a(a)(2) with a control device not tested under §60.5413a(d), identification of the storage vessel with the tested control device, the date the performance test was conducted, and pollutant(s) tested. Submit the performance test report following the procedures specified in paragraph (b)(9) of this section.

(vii) If required to comply with §60.5395a(b)(1), the information in paragraphs (b)(6)(vii)(A) through (C) of this section.

(A) Dates of each inspection required under §60.5416a(c);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of §60.5416a(c)(3).

(viii) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(ix) You must identify each storage vessel affected facility returned to service during the reporting period as specified in §60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station, report the information specified in paragraphs (b)(7)(i) through (iii) of this section, as applicable.

(i)(A) Designation of the type of site (*i.e.,* well site or compressor station) at which the collection of fugitive emissions components is located.

(B) For each collection of fugitive emissions components at a well site that became an affected facility during the reporting period, you must include the date of the startup of production or the date of the first day of production after modification. For each collection of fugitive emissions components at a compressor station that became an affected facility during the reporting period, you must include the date of startup or the date of modification.

(C) For each collection of fugitive emissions components at a well site that meets the conditions specified in either §60.5397a(a)(1)(i) or (ii), you must specify the well site is a low production well site and submit the total production for the well site.

(D) For each collection of fugitive emissions components at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site.

(E) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) of this section the removal of all major production and processing equipment and during the reporting period major production and processing equipment is added back to the well site, the date that the first piece of major production and processing equipment is added back to the well site.

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

(A) Date of the survey.

(B) Monitoring instrument used.

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

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

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

(F) Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair.

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

(iii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative fugitive emissions standard under §60.5399a, in lieu of the information specified in paragraphs (b)(7)(i) and (ii) of this section, you must provide the information specified in paragraphs (b)(7)(iii)(A) through (C) of this section.

(A) The alternative standard with which you are complying.

(B) The site-specific reports specified by the specific alternative fugitive emissions standard, submitted in the format in which they were submitted to the state, local, or tribal authority. If the report is in hard copy, you must scan the document and submit it as an electronic attachment to the annual report required in paragraph (b) of this section.

(C) If the report specified by the specific alternative fugitive emissions standard is not site-specific, you must submit the information specified in paragraphs (b)(7)(i) and (ii) of this section for each individual site complying with the alternative standard.

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

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(i)(A), (B), or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with §60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraph (b)(8)(ii)(A), (B), (C), or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with §60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) For each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(16)(ii) of this section, the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iv) If required to comply with §60.5393a(b), the information in paragraphs (b)(8)(iv)(A) through (C) of this section.

(A) Dates of each inspection required under §60.5416a(d);

(B) Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

(C) Date and time of each bypass alarm or each instance the key is checked out if you are subject to the bypass requirements of §60.5416a(c)(3).

(9) Within 60 days after the date of completing each performance test (see §60.8) required by this subpart, except testing conducted by the manufacturer as specified in §60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), except as outlined in this paragraph (b)(9)(i). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed CBI. Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (b)(9)(i). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(10) For combustion control devices tested by the manufacturer in accordance with §60.5413a(d), an electronic copy of the performance test results required by §60.5413a(d) shall be submitted via email to *Oil__and__Gas__PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *epa.gov/airquality/oilandgas/.*

(11) You must submit reports to the EPA via CEDRI, except as outlined in this paragraph (b)(11). (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, submit a complete report generated using the appropriate form in CEDRI or an alternate electronic file consistent with the XML schema listed on the EPA's CEDRI website, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage medium to the EPA. The electronic medium shall be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Fuels and Incineration Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted shall be submitted to the EPA via CEDRI. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(12) You must submit the certification signed by the qualified professional engineer or in-house engineer according to §60.5411a(d) for each closed vent system routing to a control device or process.

(13) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (b)(13)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (b)(14)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (18) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to §60.5375a(g), you must maintain the record in paragraph (c)(1)(vi) of this section, only. For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, only records of the United States Well Number, the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983, the Well Completion ID, and the date and time of startup of production are required. For periods where salable gas is unable to be separated, records of the date and time of onset of flowback, the duration and disposition of recovery, the duration of combustion and venting (if applicable), reasons for venting (if applicable), and deviations are required.

(i) Records identifying each well completion operation for each well affected facility.

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375a, including the date and time the deviation began, the duration of the deviation, and a description of the deviation.

(iii) You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas as specified in §60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in §60.5375a(a)(1)(ii).

(B) For each well affected facility required to comply with the requirements of §60.5375a(f), you must record: Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(C) For each well affected facility for which you make a claim that it meets the criteria of §60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(*2*) If applicable, records that the conditions of §60.5375a(a)(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under §60.5375a(a)(3), you must record: The latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well

Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both §60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to §60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) the latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility subject to §60.5375a(f), a record of the well type (*i.e.,* wildcat well, delineation well, or low pressure well (as defined §60.5430a)) and supporting inputs and calculations, if applicable.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380a, including a description of each deviation, the date and time each deviation began and the duration of each deviation. Except as specified in paragraph (c)(2)(viii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vii) of this section for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and (e) and used to comply with §60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model, and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(E) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(viii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup, since August 2, 2016, or since the previous replacement of the reciprocating compressor rod packing, whichever is latest. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the month and year of installation, reconstruction, or modification, location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983, identification information that allows traceability to the records required in paragraph (c)(4)(iii) or (iv) of this section and manufacturer specifications for each pneumatic controller constructed, modified, or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) For each instance where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390a, a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vii) of this section.

(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8) and 60.5416a(c)(6)(ii) and (c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this section for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and (e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) For each instance where the storage vessel was not operated in compliance with the requirements specified in §§60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable, a description of the deviation, the date and time each deviation began, and the duration of the deviation.

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

(v) You must maintain records of the identification and location in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983 of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (H) of this section for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and (e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(A) Make, model, and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15-minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, including the date of the visible emissions test, the length of the test, and the amount of time for which visible emissions were present.

(*5*) Records of the manufacturer's written operating instructions, procedures, and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) Records of deviations for instances where the inlet gas flow rate exceeds the manufacturer's listed maximum gas flow rate, where there is no indication of the presence of a pilot flame, or where visible emissions exceeded 1 minute in any 15-minute period, including a description of the deviation, the date and time the deviation began, and the duration of the deviation.

(H) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(vii) Records of the date that each storage vessel affected facility is removed from service and returned to service, as applicable.

(6) Records of each closed vent system inspection required under §60.5416a(a)(1) and (2) and (b) for centrifugal compressors and reciprocating compressors, §60.5416a(c)(1) for storage vessels, or §60.5416a(e) for pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection or no detectable emissions monitoring survey. You must include an identification number for each closed vent system (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect or leak detected during inspections required by §60.5416a(a)(1) and (2), (b), (c)(1), or (d), you must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of appendix A-7 of this part, the date of detection, and the date the repair to correct the defect or leak is completed.

(iii) If repair of the defect is delayed as described in §60.5416a(b)(10), you must record the reason for the delay and the date you expect to complete the repair.

(7) A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels as required in paragraphs (c)(7)(i) through (iii) of this section.

(i) A record of each cover inspection. You must include an identification number for each cover (or other unique identification description selected by you) and the date of the inspection.

(ii) For each defect detected during inspections required by §60.5416a(a)(3) or (c)(2), you must record the location of the defect, a description of the defect, the date of detection, the corrective action taken the repair the defect, and the date the repair to correct the defect is completed.

(iii) If repair of the defect is delayed as described in §60.5416a(b)(10) or (c)(5), you must record the reason for the delay and the date you expect to complete the repair.

(8) If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors or reciprocating compressors, or §60.5416a(c)(3) for storage vessels or pneumatic pumps, you must prepare and maintain a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) [Reserved]

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of §60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412a(d)(2)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use

Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §60.5412a(d)(1)(iii), for all inspection, repair, and maintenance activities for each control device failing the visible emissions test.

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

(i) The date of the startup of production or the date of the first day of production after modification for each collection of fugitive emissions components at a well site and the date of startup or the date of modification for each collection of fugitive emissions components at a compressor station.

(ii) For each collection of fugitive emissions components at a well site complying with §60.5397a(a)(2), you must maintain records of the daily production and calculations demonstrating that the rolling 12-month average is at or below 15 boe per day no later than 12 months before complying with §60.5397a(a)(2).

(iii) For each collection of fugitive emissions components at a well site complying with §60.5397a(a)(3)(i), you must keep records of daily production and calculations for the first 30 days after completion of any action listed in §60.5397a(a)(2)(i) through (v) demonstrating that total production from the well site is at or below 15 boe per day, or maintain records demonstrating the rolling 12-month average total production for the well site is at or below 15 boe per day.

(iv) For each collection of fugitive emissions components at a well site complying with §60.5397a(a)(3)(ii), you must keep the records specified in paragraphs (c)(15)(i), (vi), and (vii) of this section.

(v) For each collection of fugitive emissions components at a well site where you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, record the date the well site completes the removal of all major production and processing equipment from the well site, and, if the well site is still producing, record the well ID or separate tank battery ID receiving the production from the well site. If major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

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

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

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s), training, and experience of the operator(s) performing the survey.

(D) Monitoring instrument used.

(E) Fugitive emissions component identification when Method 21 of appendix A-7 of this part is used to perform the monitoring survey.

(F) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey. For compressor stations, operating mode of each compressor (*i.e.,* operating, standby pressurized, and not operating-depressurized modes) at the station at the time of the survey.

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

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

(I) Documentation of each fugitive emission detected during the monitoring survey, including the information specified in paragraphs (c)(15)(vii)(I)(*1*) through (*8*) of this section.

(*1*) Location of each fugitive emission identified.

(*2*) Type of fugitive emissions component, including designation as difficult-to-monitor or unsafe-to-monitor, if applicable.

(*3*) If Method 21 of appendix A-7 of this part is used for detection, record the component ID and instrument reading.

(*4*) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph or video must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture). The digital photograph or identification (*e.g.,* tag) may be removed after the repair is completed, including verification of repair with the resurvey.

(*5*) The date of first attempt at repair of the fugitive emissions component(s).

(*6*) The date of successful repair of the fugitive emissions component, including the resurvey to verify repair and instrument used for the resurvey.

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

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

(viii) For each collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station complying with an alternative means of emissions limitation under §60.5399a, you must maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location, and manufacturer specifications for each pneumatic pump constructed, modified, or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, and manufacturer's specifications. If the control device is designed to achieve less than 95-percent emission reduction, maintain records of the design evaluation or manufacturer's specifications which indicate the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to §60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to §60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to §60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments, and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411a(d):

(i) A copy of the assessment conducted according to §60.5411a(d)(1);

(ii) A copy of the certification according to §60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of 5 years, and make them available if directed by the delegated authority.

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

[85 FR 57449, Sept. 15, 2020]

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

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401a(b)(1).

(1) When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

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

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b)(1) through (3) and (5), and (c)(2)(i) through (iv) and (vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (3) and (5): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (iv) and (vii) through (viii):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

[81 FR 35898, June 3, 2016, as amended at 85 FR 57457, Sept. 15, 2020]

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§60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities?

(a) You must retain records of the calculations and measurements required in §§60.5405a(a) and (b) and 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The procedures for submitting annual reports are located in §60.5420a(b). For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section. The report must contain the information specified in paragraph (b)(3) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(3) For each period of excess emissions during the reporting period, include the following information in your report:

(i) The date and time of commencement and completion of each period of excess emissions;

(ii) The required minimum efficiency (Z) and the actual average sulfur emissions reduction (R) for periods defined in paragraph (b)(1) of this section; and

(iii) The appropriate operating temperature and the actual average temperature of the gases leaving the combustion zone for periods defined in paragraph (b)(2) of this section.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with §60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57458, Sept. 15, 2020]

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§60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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§60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

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, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation: $A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: Y = (CPI of date of construction/most recently available CPI of date of project), where the “CPI-U, U.S. city average, all items” must be used for each CPI value; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

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.

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

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude Oil and Natural Gas Production source category means:

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

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

Custody 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 absorption 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 in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

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

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, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing.

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.

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

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.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

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.

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 §60.5432a, is less than the flow line pressure; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Maximum average daily throughput means the following:

(1) For storage vessels that commenced construction, reconstruction, or modification after September 18, 2015, and on and before November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

(2) For storage vessels that commenced construction, reconstruction, or modification after November 16, 2020, *maximum average daily throughput* means the earliest calculation of daily average throughput, determined as described in paragraph (3) or (4) of this definition, to an individual storage vessel over the days that production is routed to that storage vessel during the 30-day PTE evaluation period employing generally accepted methods specified in §60.5365a(e)(1).

(3) If throughput to the individual storage vessel is measured on a daily basis (*e.g.,* via level gauge automation or daily manual gauging), the maximum average daily throughput is the average of all daily throughputs for days on which throughput was routed to that storage vessel during the 30-day evaluation period; or

(4) If throughput to the individual storage vessel is not measured on a daily basis (*e.g.,* via manual gauging at the start and end of loadouts), the maximum average daily throughput is the highest, of the average daily throughputs, determined for any production period to that storage vessel during the 30-day evaluation period, as determined by averaging total throughput to that storage vessel over each production period. A production period begins when production begins to be routed to a storage vessel and ends either when throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel, whichever happens first. Regardless of the determination methodology, operators must not include days during which throughput is not routed to an individual storage vessel when calculating maximum average daily throughput for that storage vessel.

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).

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

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.

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 vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

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.

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 §60.5395a(c)(1).

Repaired means, for the purposes of fugitive emissions components, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in §60.5397a and resurveyed as specified in §60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

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.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water, except as otherwise provided in this definition. For the purposes of the fugitive monitoring requirements of §60.5397a, *startup of production* means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

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

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

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 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 purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.,* centralized tank batteries). Also, for the purposes of the fugitive emissions standards at §60.5397a, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead 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 §60.5397a, 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.

[81 FR 35898, June 3, 2016, as amended at 85 FR 57072, Sept. 14, 2020; 85 FR 57458, Sept. 15, 2020]

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§60.5432a 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 §60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in §60.5430a. To determine that the well meets the definition of low pressure well in §60.5430a, you must use the low pressure well equation below:

$$P_L\,(psia) = 0.495 \times P_R - \frac{q_g}{q_g+q_o+q_w}[0.05 \times P_R + 0.038 \times L - 67.578] - \left[\frac{q_o}{q_g+q_o+q_w} \times \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] \cdot L$$

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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) ρ_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:

$$P_{BH}\,(psia) = \frac{1}{2} P_R$$

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(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, γ_{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, γ_o; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

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(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, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot {P_{BH}}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH}\ +\ 460}\right)\right]$$

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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, γ_{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, γ*o*, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

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TABLE B—COEFFICIENTS FOR THE CORRELATION FOR *B_o*

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$

C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$

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using the following equation with the value of the oil API gravity, γ_o, at the well site:

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

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(7) Calculate the density of oil at bottom hole conditions,

$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$

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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,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$

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calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

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(8) Calculate the density of oil in the well,

$\rho_o\left(\frac{lbm}{cu\ ft}\right),$

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using the following equation with the density of oil at the wellhead,

$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$

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calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH}\ (\frac{lbm}{cu\ ft}),$$

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calculated in paragraph (b)(7) of this section:

$$\rho_o\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

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(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):

$$q_o\left(\frac{cu\ ft}{sec}\right) = \mathrm{Qo}\left(\frac{\mathrm{STBO}}{\mathrm{day}}\right) \times \mathrm{Bo}\left(\frac{\mathrm{bbl}}{\mathrm{STBO}}\right) \times 5.614(\frac{\mathrm{cu\ ft}}{\mathrm{bbl}}) \times \frac{1}{24 \times 60 \times 60}(\frac{day}{sec})$$

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(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*)), γ = 0.75; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are X_{N_2} = 0.168225, X_{CO_2} = 0.013163, and X_{H_2S} = 0.013680, respectively:

$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$

$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot XCO_2 + 133.3 \cdot X_{H_2S}$

(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:

$$P_r = \frac{P_{BH}}{P_c}$$

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$$T_r = \frac{T_{BH} + 460}{T_c}$$

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(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:

$$z = A + \frac{(1-A)}{e^B} + C \cdot p_r^D$$

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(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:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2$$

$$+ \frac{0.32}{10^{9\,(T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 T_r + 0.1824 T_r^2}$$

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(13) Calculate the gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

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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:

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} ()$$

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(14) Calculate the gas flow rate,

$$q_g\left(\frac{cu\,ft}{sec}\right),$$

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using the following equation with: the value of gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

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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:

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

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(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:

$$q_w\left(\frac{cf}{sec}\right) = \text{Qw}\left(\frac{\text{bbl}}{\text{day}}\right) \times 5.614\left(\frac{\text{cf}}{\text{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

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§§60.5433a-60.5439a [Reserved]

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Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ 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

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Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ 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 §60.5425a, you must comply with the following applicable General Provisions:

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Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5430a.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420a(a).
§60.8	Performance tests	Yes	Except that the format of performance test reports is described in §60.5420a(b). Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
§60.9	Availability of information	Yes	
§60.10	State authority	Yes	

§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes	To the extent any provision in §60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§60.15	Reconstruction	Yes	Except that §60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device and work practice requirements	Yes	
§60.19	General notification and reporting requirement	Yes	

[81 FR 35898, June 3, 2016, as amended at 85 FR 57460, Sept. 15, 2020]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of November 19, 2020

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING

Subpart W—Petroleum and Natural Gas Systems

Contents

SOURCE: 75 FR 74488, Nov. 30, 2010, unless otherwise noted.

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§98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well pad using CO_2 or natural gas injection.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This

segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to

compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

(10) *Onshore natural gas transmission pipeline.* Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in §98.238.

(b) [Reserved]

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64283, Oct. 22, 2015]

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§98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of §98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in §98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in §98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in §98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in §98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in §98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64284, Oct. 22, 2015]

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§98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a single well-pad or associated with a single well-pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Well venting during well completions with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(22) You must use the methods in §98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in §98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel. If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(f) For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) Flare stack emissions.

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations.

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(7) Equipment leaks from valves, connectors, open-ended lines, and pressure relief valves associated with storage wellheads.

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject

wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a, of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(g) For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Flare stack emissions.

(4) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(5) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (g)(6) of this section.

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(h) LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Flare stack emissions.

(5) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(6) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (h)(7) of this section.

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(i) For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations.

(2) Equipment leaks at below grade transmission-distribution transfer stations.

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks.

(6) Distribution services equipment leaks.

(7) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in §98.233(z).

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in §98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in §98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: Natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

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§98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For calculations that specify measurements in actual conditions, reporters may use a flow or volume measurement system that corrects to standard conditions and determine the flow or volume at standard conditions; otherwise, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types "t" (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type "t" (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type "t" listed in Tables W-1A, W-3B, and W-4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W-1A to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type "t", were operational using engineering estimates based on best available data. Default is 8,760 hours.

(1) For all industry segments, determine "$Count_t$" for Equation W-1 of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(2) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W-1 of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W-1 for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* (1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W-2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under this paragraph (c).

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps.

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W-1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps were operational using engineering estimates based on best available data. Default is 8,760 hours.

(2) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(d) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through a flare, engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant, using any of the calculation methods described in this paragraph (d), as applicable.

(1) *Calculation Method 1.* If you operate and maintain a continuous emissions monitoring system (CEMS) that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Method in subpart C of this part (General Stationary Fuel Combustion Sources). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGR units.

(2) *Calculation Method 2.* If a CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

$$E_{a,CO_2} = V_s * Vol_{CO_2} \qquad \text{(Eq. W-3)}$$

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Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in §98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_{CO2} = Annual average volumetric fraction of CO_2 content in vent gas flowing out of the AGR unit as determined in paragraph (d)(6) of this section.

(3) *Calculation Method 3.* If a CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations W-4A or W-4B of this section. If inlet gas flow rate is known, use Equation W-4A. If outlet gas flow rate is known, use Equation W-4B.

$$E_{a,CO2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O}\right] \qquad \text{(Eq. W-4A)}$$

$$E_{a,CO2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I}\right] \qquad \text{(Eq. W-4B)}$$

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Where:

$E_{a,\,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Annual average volumetric fraction of CO_2 content in natural gas flowing into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_o = Annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Method 4.* If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CO_2 emissions. A minimum of the following, determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data, must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) For Calculation Method 3, determine the gas flow rate of the inlet when using Equation W-4A of this section or the gas flow rate of the outlet when using Equation W-4B of this section for the natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) For Calculation Method 2, if a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream for each quarter that the AGR unit is operating to determine Vol_{CO2} in Equation W-3 of this section, according to the methods set forth in §98.234(b).

(7) For Calculation Method 3, if a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream for each quarter that the AGR unit is operating to determine Vol_I in Equation W-4A or W-4B of this section, according to the methods set forth in §98.234(b).

(8) For Calculation Method 3, determine annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit using one of the methods specified in

paragraphs (d)(8)(i) through (d)(8)(iii) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream for each quarter that the AGR unit is operating to determine Vol_O in Equation W-4A or W-4B of this section, according to the methods set forth in §98.234(b).

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

(9) Calculate annual volumetric CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Calculate annual mass CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if CO_2 emissions from the AGR unit are recovered and transferred outside the facility. Adjust the CO_2 emissions estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of CO_2 emissions recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (e)(4) of this section. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(5) of this section. If emissions from dehydrator vents are routed to a flare or regenerator fire-box/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(6) of this section.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI-GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. The following parameters must be determined by engineering estimate based on best available data and must be used at a minimum to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (*e.g.,* natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG)).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) through (D) of this section.

(A) Use the GHG mole fraction as defined in paragraph (u)(2)(i) or (ii) of this section.

(B) If the GHG mole fraction cannot be determined using paragraph (u)(2)(i) or (ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W-5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

(3) *Calculation Method 3.* For dehydrators of any size that use desiccant, you must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W-6 of this section. Desiccant dehydrator emissions covered in this paragraph do not have to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

$$E_{s,n} = \frac{\left(H * D^2 * \pi * P_2 * \%G * N\right)}{\left(4 * P_1 * 100\right)} \qquad \text{(Eq. W-6)}$$

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Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

π = pi (3.14).

%G = Percent of packed vessel volume that is gas.

N = Number of dehydrator openings in the calendar year.

100 = Conversion of %G to fraction.

(4) For glycol dehydrators that use the calculation method in paragraph (e)(2) of this section, calculate both CH_4 and CO_2 mass emissions from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For desiccant dehydrators that use the calculation method in paragraph (e)(3) of this section, calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1), (2), and (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(6) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(i) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) through (5) of this section, as applicable.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(f) *Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (f)(1), (2), or (3) of this section. Calculate annual CH_4 and CO_2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1) *Calculation Method 1.* Calculate emissions from wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see §98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (*e.g.,* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in §98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W-7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

$$E_a = FR \sum_{p=1}^{h} T_p \qquad \text{(Eq. W-7A)}$$

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Where:

E_a = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, T_p, using Equation W-7B of this section.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

$$T_p = \frac{HR_p}{MP_p} \text{ x } D_p \qquad \text{(Eq. W-7B)}$$

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Where:

HR_p = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MP_p = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate ("FR" in Equation W-7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with plunger lifts and wells without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Method 2.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-8)}$$

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Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period per well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p = Casing internal diameter for each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure

pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for each well, you may determine the casing pressure by multiplying the tubing pressure of each well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3) *Calculation Method 3.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-9)}$$

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Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period for each well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(4) Calculate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W-10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W-10A, you must follow the procedures specified in paragraph (g)(1). If you elect to use Equation W-10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

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Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in §98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in §98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in §98.234(b).

(1) If you elect to use Equation W-10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section, to determine the value of FRM_s and FRM_i. If you elect to use Equation W-10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use Equation W-12A of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation

W-12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W-12A and W-12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in §98.234(b).

(ii) *Calculation Method 2 (for gas wells).* You must use Equation W-12A as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W-12B as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) also apply. When calculating the flowback rates for use in Equations W-12A and W-12B of this section based on well parameters, you must record the well flowing pressure immediately upstream (and immediately downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate the well flowback. The upstream pressure must be surface pressure and reservoir pressure cannot be assumed. The downstream pressure must be measured after the choke and atmospheric pressure cannot be assumed. Calculate flowback rate using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. You must use best engineering estimates based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C of this section is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic. Convert calculated FR_a values from actual conditions upstream of the restriction orifice to standard conditions ($FR_{s,p}$ and $FR_{i,p}$) for use in Equations W-12A and W-12B of this section using Equation W-33 in paragraph (t) of this section.

$$FR_a = 1.27*10^5 * A * \sqrt{3430*T_u*\left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \qquad \text{(Eq. W-11A)}$$

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Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Pressure immediately upstream of the choke (psia).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

P_2 = Pressure immediately downstream of the choke (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR_a = 1.27*10^5 * A * \sqrt{187.08*T_u} \qquad \text{(Eq. W-11B)}$$

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Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$R = {}^{P1}\!/_{P2} \qquad \text{(Eq. W-11C)}$$

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Where:

R = Pressure ratio.

P_1 = Pressure immediately upstream of the choke (psia).

P_2 = Pressure immediately downstream of the choke (psia).

(iii) For Equation W-10A of this section, calculate FRM_s using Equation W-12A of this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12A)}$$

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Where:

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W-33 in paragraph (t) of this section. You may not use flow volume as used in Equation W-10B of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For Equation W-10A of this section, calculate FRM_i using Equation W-12B of this section.

$$FRMi = \frac{\sum_{p=1}^{N} FR_{i,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12B)}$$

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Where:

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or initial calculated flow rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured and calculated $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions.

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(v) For Equation W-10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For Equations W-12A and W-12B of this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W-10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W-12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

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Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in §98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

(i) Vertical or horizontal (directional drilling).

(ii) With flaring or without flaring.

(iii) Reduced emission completion/workover or not reduced emission completion/workover.

(iv) Oil well or gas well.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions from total natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(4) Calculate annual emissions from well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

(i) Use the volumetric total natural gas emissions vented to the atmosphere during well completions and workovers as determined in paragraph (g) of this section to calculate volumetric and mass emissions using paragraphs (u) and (v) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to adjust emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing. This adjustment to emissions from completions using flaring, versus completions without flaring, accounts for the conversion of CH_4 to CO_2 in the flare and for the formation on N_2O during flaring.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using Equation W-13A of this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using Equation W-13B of this section. You must convert annual volumetric natural gas emissions to CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (h)(1) of this section. If emissions from gas well venting during completions and workovers without hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (h)(2) of this section.

$$E_{s,wo} = N_{wo} * EF_{wo} \qquad \text{(Eq. W-13A)}$$

$$E_{s,p} = \sum_{p=1}^{f} V_p * T_p \qquad \text{(Eq. W-13B)}$$

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Where:

$E_{s,wo}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well workovers without hydraulic fracturing.

N_{wo} = Number of workovers per sub-basin category that do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. Use 3,114 standard cubic feet natural gas per well workover without hydraulic fracturing.

$E_{s,p}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well completions without hydraulic fracturing.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

V_p = Average daily gas production rate in standard cubic feet per hour for each well, p, undergoing completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_p = Time that gas is vented to either the atmosphere or a flare for each well, p, undergoing completion without hydraulic fracturing, in hours during the year.

(1) Calculate both CH_4 and CO_2 volumetric emissions from natural gas volumetric emissions using calculations in paragraph (u) of this section. Calculate both CH_4 and CO_2 mass emissions from volumetric emissions vented to atmosphere using calculations in paragraph (v) of this section.

(2) Calculate annual emissions of CH_4, CO_2, and N_2O from gas well venting to flares during well completions and workovers not involving hydraulic fracturing as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) Use the gas well venting volume and gas composition during well completions and workovers that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading.

(1) *Method for calculating unique physical volumes.* You must calculate each unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves, in cubic feet, by using engineering estimates based on best available data.

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the

following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) Calculate the total annual natural gas emissions from each unique physical volume that is blown down using either Equation W-14A or W-14B of this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

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Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume between isolation valves, in cubic feet, as calculated in paragraph (i)(1) of this section.

C = Purge factor is 1 if the unique physical volume is not purged, or 0 if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

$$E_{s,n} = \sum_{p=1}^{N} \left[V_p \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s Z_a} \right) \right] \quad \text{(Eq. W-14B)}$$

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Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V_p = Unique physical volume between isolation valves, in cubic feet, for each blowdown “p.”

T_s = Temperature at standard conditions (60 °F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown “p”.

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown “p”.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown “p”; 0 if blowdown volume is purged using non-GHG gases.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(ii) Except as allowed in paragraph (i)(2)(iii) of this section, calculate annual CH_4 and CO_2 volumetric and mass emissions from each unique physical volume that is blown down by using the annual natural gas emission value as calculated in either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section and the calculation method specified in paragraph (i)(4) of this section. Calculate the total annual CH_4 and CO_2 emissions for each equipment or event type by summing the annual CH_4 and CO_2 mass emissions for all unique physical volumes associated with the equipment or event type.

(iii) For onshore natural gas transmission compression facilities and LNG import and export equipment, as an alternative to using the procedures in paragraph (i)(2)(ii) of this section, you may elect to sum the annual natural gas emissions as calculated using either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section for all unique physical volumes associated with the equipment type or event type. Calculate the total annual CH_4 and CO_2 volumetric and mass emissions for each equipment type or event type using the sums of the total annual natural gas emissions for each equipment type and the calculation method specified in paragraph (i)(4) of this section.

(3) *Method for determining emissions from blowdown vent stacks using a flow meter.* In lieu of determining emissions from blowdown vent stacks as specified in paragraph (i)(2) of this section, you may use a flow meter and measure blowdown vent stack emissions for any unique physical volumes determined according to paragraph (i)(1) of this section to be greater than or equal to 50 cubic feet. If you choose to use this method, you must measure the natural gas emissions from the blowdown(s) through the monitored stack(s) using a flow meter according to methods in §98.234(b), and calculate annual CH_4 and CO_2 volumetric and mass emissions measured by the meters according to paragraph (i)(4) of this section.

(4) *Method for converting from natural gas emissions to GHG volumetric and mass emissions.* Calculate both CH_4 and CO_2 volumetric and mass emissions using the methods specified in paragraphs (u) and (v) of this section.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator or non-separator equipment enters an atmospheric pressure storage tank. The following parameters must be determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in §98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(iii) *Flow to storage tank direct from non-separator equipment.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W-15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(4) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

determined by engineering estimate based on best available data.

(ii) [Reserved]

(5) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W-16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \quad \text{(Eq. W-16)}$$

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Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

(7) Calculate both CH_4 and CO_2 mass emissions from natural gas volumetric emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (k)(4) of this section. If emissions from compressor scrubber dump valve leakage are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (k)(5) of this section.

(1) Except as specified in paragraph (k)(1)(iv) of this section, you must monitor the tank vapor vent stack annually for emissions using one of the methods specified in paragraphs (k)(1)(i) through (iii) of this section.

(i) Use an optical gas imaging instrument according to methods set forth in §98.234(a)(1).

(ii) Measure the tank vent directly using a flow meter or high volume sampler according to methods in §98.234(b) or (d) for a duration of 5 minutes.

(iii) Measure the tank vent using a calibrated bag according to methods in §98.234(c) for a duration of 5 minutes or until the bag is full, whichever is shorter.

(iv) You may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the optical gas imaging instrument or acoustic leak detection device detects a leak, then you must use one of the methods in either paragraph (k)(2)(i) or (ii) of this section.

(i) Use a flow meter, such as a turbine meter, calibrated bag, or high volume sampler to estimate tank vapor volumes from the vent stack according to methods set forth in §98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (k)(1)(ii) or (iii) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5).

(3) If a leaking dump valve is identified, the leak must be counted as having occurred since the beginning of the calendar year, or from the previous test that did not detect leaking in the same calendar year. If the leaking dump valve is fixed following leak detection, the leak duration will end upon being repaired. If a leaking dump valve is identified and not repaired, the leak must be counted as having occurred through the rest of the calendar year.

(4) Use the requirements specified in paragraphs (k)(4)(i) and (ii) of this section to quantify annual emissions.

(i) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(ii) Calculate CH_4 and CO_2 volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(5) Calculate annual emissions from storage tanks to flares as specified in paragraphs (k)(5)(i) and (ii) of this section.

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(l) *Well testing venting and flaring.* Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (l)(6) of this section.

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the procedures specified in paragraph (l)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W-17A (for oil wells) or Equation W-17B (for gas wells) of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \quad \text{(Eq. W-17B)}$$

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Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Average annual flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the calendar year that the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing if emissions are routed to a flare as specified in paragraphs (l)(6)(i) and (ii) of this section.

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as specified in paragraphs (m)(1) through (4) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (m)(5) of this section.

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

(2) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraphs (m)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W-18 of this section.

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} \left[\left(GOR_{p,q} * V_{p,q} \right) - SG_{p,q} \right] \qquad \text{(Eq. W-18)}$$

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Where:

$E_{s,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting at standard conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during time periods in which associated gas was vented or flared.

$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year during time periods in which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate emissions from associated natural gas if emissions are routed to a flare as specified in paragraphs (m)(5)(i) and (ii) of this section.

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as specified in paragraphs (n)(1) through (9) of this section.

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in paragraphs (n)(2)(i) through (iii) of this section.

(i) For onshore natural gas production and onshore petroleum and natural gas gathering and boosting, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid for all streams.

(iii) For any industry segment required to report to flare stack emissions under §98.232, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section.

$$E_{s,CH4} = V_s * X_{CH4} * \left[(1-\eta) * Z_L + Z_U\right] \quad \text{(Eq. W-19)}$$

$$E_{s,CO2} = V_s * X_{CO2} + \sum_{j=1}^{5}\left(\eta * V_s * Y_j * R_j * Z_L\right) \quad \text{(Eq. W-20)}$$

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Where:

$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

Z_U = Fraction of the feed gas sent to an un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare (equal to $1 - Z_U$).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare as determined in paragraph (n)(1) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculation in paragraph (v) of this section.

(7) Calculate N_2O emissions from flare stacks using Equation W-40 in paragraph (z) of this section.

(8) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the flare, you must calculate only CO_2 emissions for the flare. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (7) of this section are not required.

(9) The flare emissions determined under this paragraph (n) must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in §98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in §98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

(1) *General requirements for conducting volumetric emission measurements.* You must conduct volumetric emission measurements on each centrifugal compressor as specified in this paragraph. Compressor sources (as defined in §98.238) without manifolded vents must use a measurement method specified in paragraph (o)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in §98.238) must use a measurement method specified in paragraph (o)(1)(i), (ii), (iii), or (iv) of this section.

(i) Centrifugal compressor source as found measurements. Measure venting from each compressor according to either paragraph (o)(1)(i)(A) or (B) of this section at least once annually, based on the compressor mode (as defined in §98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (o)(1)(i)(C) and (D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (o)(2)(i)(A) or (B) of this section and, if the compressor has wet seal oil degassing vents, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (o)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) You must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at least once in any three consecutive calendar years, provided the measurement section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If three consecutive calendar years occur without measuring the compressor in not-operating-depressurized-mode, you must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at the next scheduled depressurized shutdown. The requirement specified in this paragraph does not apply if the compressor has blind flanges in place throughout the reporting year. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (o)(6)(ii) of this section.

(ii) Centrifugal compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (o)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (o)(3) of this section.

(iii) Manifolded centrifugal compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in §98.238), instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (o)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (o)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded centrifugal compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressor sources as specified in paragraph (o)(5) of this section.

(2) *Methods for performing as found measurements from individual centrifugal compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, and the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(i) For blowdown valves on compressors in operating-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions compressors in not operating depressurized mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer according to methods set forth in §98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(D) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (o)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the methods.

(ii) For wet seal oil degassing vents in operating-mode, determine vapor volumes at standard conditions, using a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in §98.234(b).

(3) *Methods for continuous measurement from individual centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (o)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (o)(3)(i) and (ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor source at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of centrifugal compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (o)(4)(i) and (ii) of this section.

(i) 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.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in §98.234(b).

(B) Calibrated bagging according to methods set forth in §98.234(c).

(C) A high volume sampler according to methods set forth §98.234(d).

(D) An acoustic leak detection device according to methods set forth in §98.234(a)(5).

(E) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (o)(4)(ii)(D) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) *Methods for continuous measurement from manifolded groups of centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (o)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) 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.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(i) of this section, you must calculate annual GHG emissions from the compressor sources as specified in paragraphs (o)(6)(i) through (iv) of this section.

(i) Using Equation W-21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) and (B) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-21)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (o)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was measured for the reporting year.

(ii) Using Equation W-22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-22)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (o)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was not measured in the reporting year.

(iii) Using Equation W-23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section. These emission factors must be calculated annually and used in Equation W-22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-23)}$$

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Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-21 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section.

(iv) The reporter emission factor in Equation W-23 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-24A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-24A)}$$

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Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of centrifugal compressor sources.* For manifolded groups of compressor sources measured according to paragraph (o)(1)(iii) of this section, you must calculate annual volumetric GHG emissions using Equation W-24B of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(8) or paragraph (p)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-24B)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (o)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of centrifugal compressor sources.* For a manifolded group of compressor sources measured according to paragraph (o)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-24C of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(9) or paragraph (p)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g}=Q_{s,g}*GHG_{i,g} \qquad \text{(Eq. W-24C)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-25 of this section.

$$E_{s,i}=Count*EF_{i,s} \qquad \text{(Eq. W-25)}$$

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Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) *General requirements for calculating volumetric GHG emissions from centrifugal compressors routed to flares.* You must calculate and report emissions from all centrifugal compressor sources that are routed to a flare as specified in paragraphs (o)(12)(i) through (iii) of this section.

(i) Paragraphs (o)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in §98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in §98.236(o).

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in §98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in §98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

(1) *General requirements for conducting volumetric emission measurements.* You must conduct volumetric emission measurements on each reciprocating compressor as specified in this paragraph. Compressor sources (as defined in §98.238) without manifolded vents must use a measurement method specified in paragraph (p)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in §98.238) must use a measurement method specified in paragraph (p)(1)(i), (ii), (iii), or (iv) of this section.

(i) Reciprocating compressor source as found measurements. Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in §98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (p)(1)(i)(D) and (E) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) of this section.

(B) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section.

(C) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (p)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(D) You must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If there is no scheduled shutdown within three consecutive calendar years, you must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at the next scheduled depressurized shutdown. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(E) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

(ii) Reciprocating compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (p)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (p)(3) of this section.

(iii) Manifolded reciprocating compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in §98.238), instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (p)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (p)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded reciprocating compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressors sources as specified in paragraph (p)(5) of this section.

(2) *Methods for performing as found measurements from individual reciprocating compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section.

(i) For blowdown valves on compressors in operating-mode or standby-pressurized-mode, and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer, according to methods set forth in §98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(D) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraphs (p)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

(A) Determine the volumetric flow at standard conditions from the open-ended vent line using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the open-ended vent line using a temporary meter such as a vane anemometer, according to methods set forth in §98.234(b).

(C) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (p)(2)(ii)(A) and (p)(4)(ii)(B) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(iii) For reciprocating rod packing not equipped with an open-ended vent line on compressors in operating-mode, you must determine the volumetric emissions using the method specified in paragraphs (p)(2)(iii)(A) and (B) of this section.

(A) You must use the methods described in §98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(B) You must measure emissions found in paragraph (p)(2)(iii)(A) of this section using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in §98.234(b), (c), and (d), respectively.

(3) *Methods for continuous measurement from individual reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (p)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (p)(3)(i) and (p)(3)(ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of reciprocating compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (p)(4)(i) and (ii) of this section.

(i) 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.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (p)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in §98.234(b).

(B) Calibrated bagging according to methods set forth in §98.234(c).

(C) A high volume sampler according to methods set forth §98.234(d).

(D) An acoustic leak detection device according to methods set forth in §98.234(a)(5).

(E) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) *Methods for continuous measurement from manifolded groups of reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (p)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) 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.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(i) of this section, you must calculate GHG emissions from the compressor sources as specified in paragraphs (p)(6)(i) through (iv) of this section.

(i) Using Equation W-26 of this section, calculate the annual volumetric GHG emissions for each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-26)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (p)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W-27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-27)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (p)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section that was not measured for the reporting year.

(iii) Using Equation W-28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section. These emission factors must be calculated annually and used in Equation W-27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-28)}$$

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Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-26 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section.

(iv) The reporter emission factor in Equation W-28 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-29A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-29A)}$$

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Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of reciprocating compressor sources.* For manifolded groups of compressor sources measured according to paragraph (p)(1)(iii) of this section, you must calculate annual GHG emissions using Equation W-29B of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(8) or paragraph (o)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-29B)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (p)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of reciprocating compressor sources.* For a manifolded group of compressor sources measured according to paragraph (p)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-29C of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(9) or paragraph (o)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \qquad \text{(Eq. W-29C)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-29D of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-29D)}$$

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Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) *General requirements for calculating volumetric GHG emissions from reciprocating compressors routed to flares.* You must calculate and report emissions from all reciprocating compressor sources that are routed to a flare as specified in paragraphs (p)(12)(i) through (iii) of this section.

(i) Paragraphs (p)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in §98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in §98.236(p).

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in §98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you must conduct surveys using any of the leak detection methods listed in §98.234(a) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(ii) For the components listed in §98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in §98.234(a)(1) through (5) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iii) For the components listed in §98.232(c)(21), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in §98.234(a)(6) or (7) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iv) For the components listed in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in §60.5397a of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in §98.234(a).

(A) If you elect to use a leak detection method in §98.234(a)(1) through (5) for the surveyed component types in §98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in §98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) using the procedures in paragraph (q)(2) of this section.

(B) If you elect to use a leak detection method in §98.234(a)(1) through (5) for the surveyed component types in §98.232(e)(8), (f)(6), (f)(8), (g)(7), and (h)(8), then you must use the procedures in paragraph (q)(2) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in §98.234(a)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in §60.5397a of this chapter, and you must calculate emissions from the surveyed component types in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in paragraph (q)(2) of this section.

(2) *Emission calculation methodology.* For industry segments listed in §98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W-30 of this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in §98.230(a)(8), the results from Equation W-30 are used to calculate population emission factors on a meter/regulator run basis using Equation W-31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, “n,” according to paragraph (q)(2)(x)(A) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \qquad \text{(Eq. W-30)}$$

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Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type “p” (in accordance with paragraphs (q)(1)(i) through (iv) of this section) in standard (“s”) cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type “p” detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Tables W-1E, W-2, W-3A, W-4A, W-5A, W-6A, and W-7 to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

$T_{p,z}$ = The total time the surveyed component “z,” component type “p,” was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(i) You must conduct at least one leak detection survey in a calendar year. The leak detection surveys selected must be conducted during the calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using Equation W-30. For components subject to the well site and compressor station fugitive emissions standards in §60.5397a of this chapter, each survey conducted in accordance with §60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors for components in gas service, light crude service, and heavy crude service listed in Table W-1E to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas leaker factors for components in gas service listed in Table W-1E to this subpart.

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-2 to this subpart.

(vi) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-3A to this subpart.

(vii) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in Table W-4A to this subpart.

(viii) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in Table W-5A to this subpart.

(ix) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in Table W-6A to this subpart.

(x) Natural gas distribution facilities must use Equation W-30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W-7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section.

(A) Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years "n," not exceeding a five year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(B) Use Equation W-31 of this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i annually according to paragraph (q)(2)(x)(C) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

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Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type "p" during year "y" in standard ("s") cubic feet, as calculated using Equation W-30 of this section.

p = Seven component types listed in Table W-7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run "w" was operational, in hours during survey year "y" using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year "y".

y = Year of data included in emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(C) of this section.

n = Number of years of data, according to paragraph (q)(2)(x)(A) of this section, whose results are used to calculate emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(C) of this section.

(C) The emission factor "$EFs,_{MR,i,}$" based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(2)(x)(A) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor "$EF_{s,MR,i}$" from Equation W-31 of this section.

After the first survey cycle of “n” years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year “y” and survey results from all previous (n−1) calendar years, such that each annual calculation of the emission factor “$EF_{s,MR,i}$” from Equation W-31 is based on survey results from “n” years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate “$EF_{s,MR,i}$” from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, “n_{new},” in the new cycle is smaller than the number of years in the previous cycle, “n,” calculate “$EF_{s,MR,i}$” from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous (n_{new}−1) calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, “n,” according to paragraph (q)(2)(x)(A) of this section, you must use the meter/regulator run population emission factors calculated using Equation W-31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W-32B in paragraph (r) of this section.

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in §98.232(c)(21), (f)(7), (g)(5), (h)(6), and (j)(10) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in §98.232(i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W-32A of this section, except for natural gas distribution facility emission sources listed in §98.232(i)(3). Natural gas distribution facility emission sources listed in §98.232(i)(3) must calculate emissions using Equation W-32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \qquad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \qquad \text{(Eq. W-32B)}$$

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Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W-1B and Table W-1C to this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W-4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W-7 to this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W-1A, W-4B, W-5B, W-6B, and W-7 to this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W-1D to this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W-31 of this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W-1A of this subpart. Major equipment and

components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems are considered gas service components in reference to Table W-1A of this subpart and major natural gas equipment in reference to Table W-1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W-1A of this subpart and major crude oil equipment in reference to Table W-1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W-1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the calculation methods described in this paragraph (r)(2), except for miles of gathering pipelines by material type, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. The same calculation method must be used for the entire calendar year.

(i) *Component Count Method 1.* For all onshore petroleum and natural gas production operations and onshore petroleum and natural gas gathering and boosting operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W-1B and Table W-1C of this subpart. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(B) Multiply major equipment counts by the average component counts listed in Table W-1B of this subpart for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W-1C of this subpart for onshore oil production. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(ii) *Component Count Method 2.* Count each component individually for the facility. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in Table W-4B to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W-5B to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas service listed in Table W-6B to this subpart.

(6) Natural gas distribution facilities must use the appropriate methane emission factors as described in paragraphs (r)(6)(i) and (ii) of this section.

(i) Below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W-7 of must use the appropriate default methane population emission factors listed in Table W-7 of this subpart. Below grade transmission-distribution transfer stations must use the emission factor for below grade metering-regulating stations.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W-31. Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in §98.236(r)(2)(v).

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction must use the most recent monitoring methods and calculation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report annual emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle

must use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report emissions.

(t) *GHG volumetric emissions using actual conditions.* If equation parameters in §98.233 are already determined at standard conditions as provided in the introductory text in §98.233, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation W-33 of this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-33)}$$

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Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet, except $E_{s,n}$ equals $FR_{s,p}$ for each well p when calculating either subsonic or sonic flowrates under §98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under §98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W-34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-34)}$$

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Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a.i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for GHG i.

You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) *GHG volumetric emissions at standard conditions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W-35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

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where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W-35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(iv) *GHG mole fraction in natural gas stored in the underground natural gas storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mole fraction in natural gas stored in the LNG storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vi) *GHG mole fraction in natural gas stored in the LNG import and export industry segment.* For export facilities that receive gas from transmission pipelines, you may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vii) *GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mass emissions.* Calculate GHG mass emissions in metric tons by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W-36 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. W-36)}$$

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Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from each EOR injection pump system as follows:

(1) Calculate the total injection pump system volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual CO_2 emissions from each EOR injection pump system using Equation W-37 of this section:

$$Mass_{CO2} = N * V_v * R_c * GHG_{CO2} * 10^{-3} \quad \text{(Eq. W-37)}$$

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Where:

$Mass_{CO2}$ = Annual EOR injection pump system emissions in metric tons from blowdowns.

N = Number of blowdowns for the EOR injection pump system in the calendar year.

V_v = Total volume in cubic feet of EOR injection pump system chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_{CO2} = Mass fraction of CO_2 in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) *EOR hydrocarbon liquids dissolved CO_2.* Calculate CO_2 emissions downstream of the storage tank from dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples of hydrocarbon liquids downstream of the storage tank must be taken according to methods set forth in §98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W-38 of this section.

$$Mass_{CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

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Where:

$Mass_{CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraphs (z)(3) and (4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (z)(1)(i) of this section. If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation method described in paragraph (z)(1)(i) of this section and you may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per standard cubic feet, calculate emissions according to paragraph (z)(2) of this section. If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (z)(2) of this section.

(i) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in §98.33, any monitoring or QA/QC requirements listed for that tier in §98.34, any missing data procedures specified in §98.35, and any recordkeeping requirements specified in §98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities will be reported according to the requirements specified in §98.236(z) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39A and W-39B of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \quad \text{(Eq. W-39A)}$$

$$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4} \quad \text{(Eq. W-39B)}$$

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Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH4} = Mole fraction of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(vi) Calculate N_2O mass emissions using Equation W-40 of this section.

$$Mass_{N2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

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Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a high heat value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in §98.231(a). You must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in §98.231(a). You must report the type and number of each internal fuel combustion unit.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80575, Dec. 23, 2011; 77 FR 51490, Aug. 24, 2012; 78 FR 71960, Nov. 29, 2013; 79 FR 70408, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

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§98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of through-valve leakage from all source types listed in §98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(i) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(ii) that occur during a calendar year. You must use one of the methods described in paragraph (a)(6) or (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(iii). If electing to comply with §98.233(q) as specified in §98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from component types as specified in §98.233(q)(1)(iv) that occur during a calendar year.

(1) *Optical gas imaging instrument as specified in §60.18 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18 of the *Alternative work practice for monitoring equipment leaks,* §60.18(i)

(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels;* §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

(6) Optical gas imaging instrument as specified in §60.5397a of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with §60.5397a(b), (c)(3), (c)(7), and (e) of this chapter and paragraphs (a)(6)(i) through (iii) of this

section. Unless using methods in paragraph (a)(7) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(i) For the purposes of this subpart, any visible emissions from a component listed in §98.232 observed by the optical gas imaging instrument is a leak.

(ii) For the purposes of this subpart, the term “fugitive emissions component” in §60.5397a of this chapter means “component.”

(iii) For the purpose of complying with §98.233(q)(1)(iv), the phrase “the collection of fugitive emissions components at well sites and compressor stations” in §60.5397a(b) of this chapter means “the collection of components for which you elect to comply with §98.233(q)(1)(iv).”

(7) Method 21 as specified in §60.5397a of this chapter. Use the equipment leak detection methods in appendix A-7 to part 60 of this chapter, Method 21, in accordance with §60.5397a(b), (c)(8), and (e) of this chapter and paragraphs (a)(7)(i) through (iii) of this section. Inaccessible emissions sources, as defined in part 60 of this chapter, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(6) of this section to monitor inaccessible equipment leaks.

(i) For the purposes of this subpart, any instrument reading from a component listed in §98.232 of this chapter of 500 ppm or greater using Method 21 is a leak.

(ii) For the purposes of this subpart, the term “fugitive emissions component” in §60.5397a of this chapter means “component.”

(iii) For the purpose of complying with §98.233(q)(1)(iv), the phrase “the collection of fugitive emissions components at well sites and compressor stations” in §60.5397a(b) of this chapter means “the collection of components for which you elect to comply with §98.233(q)(1)(iv).”

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in §98.233 according to the procedures in §98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methods relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W-41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-41)}$$

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Where:

p = Absolute pressure.

R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724R^2T_c^2}{p_c}$$

$$b = \frac{0.7780\,RT_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

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Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) *Special reporting provisions for best available monitoring methods in reporting year 2015*—(1) *Best available monitoring methods.* From January 1, 2015 to March 31, 2015, for a facility subject to this subpart, you must use the calculation methodologies and equations in §98.233 “Calculating GHG Emissions”, but you may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2015 as specified in paragraphs (f)(2) and (3) of this section. Starting no later than April 1, 2015, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (f)(4) of this section. Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related measurement data.* You may use best available monitoring methods for well-related measurement data identified in paragraphs (f)(2)(i) and (ii) of this section that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart.

(i) If Calculation Method 1 for liquids unloading in §98.233(f)(1) was used in calendar year 2014 and will be used again in calendar year 2015, the vented natural gas flow rate for any well in a unique tubing diameter group and pressure group combination that has not been previously measured.

(ii) If using Equation W-10A of this subpart to determine natural gas emissions from completions and workovers for representative wells, the initial and average flowback rates (when using Calculation Method 1 in §98.233(g)(1)(i)) or pressures upstream and downstream of the choke (when using Calculation Method 2 in §98.233(g)(1)(ii)) for any well in a well type combination that has not been previously measured.

(3) *Best available monitoring methods for emissions measurement.* You may use best available monitoring methods for sources listed in paragraphs (f)(3)(i) and (ii) of this section if the required measurement data cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part.

(i) Centrifugal compressor as found measurements of manifolded emissions from groups of centrifugal compressor sources according to §98.233(o)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(ii) Reciprocating compressor as found measurements of manifolded emissions from groups of reciprocating compressor sources according to §98.233(p)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(4) *Requests for extension of the use of best available monitoring methods beyond March 31, 2015.* You may submit a request to the Administrator to use one or more best available monitoring methods for sources listed in paragraphs (f)(2) and (3) of this section beyond March 31, 2015.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31, 2015.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific source types and parameters for which you are seeking use of best available monitoring methods.

(B) For each specific source type for which you are requesting use of best available monitoring methods, a description of the reasons that the needed equipment could not be obtained and installed before April 1, 2015.

(C) A description of the specific actions you will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) *Approval criteria.* To obtain approval to use best available monitoring methods after March 31, 2015, you must submit a request demonstrating to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2015. The use of best available methods under paragraph (f) of this section will not be approved beyond December 31, 2015.

(g) *Special reporting provisions for best available monitoring methods in reporting year 2016*—(1) *Best available monitoring methods.* From January 1, 2016, to December 31, 2016, you must use the calculation methodologies and equations in §98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in §98.231(a)(1).

(2) Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(3) *Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.* You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(4) *Best available monitoring methods for measurement data for onshore petroleum and natural gas gathering and boosting facilities.* You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in §98.233(d).

(5) *Best available monitoring methods for measurement data for natural gas transmission pipelines.* You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(6) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic

fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in §98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in §98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs §98.233(d), (e), (j), (n), and (z).

(h) For well venting for liquids unloading, if a monitoring period other than the full calendar year is used to determine the cumulative amount of time in hours of venting for each well (the term "T_p" in Equation W-7A and W-7B of §98.233) or the number of unloading events per well (the term "V_p" in Equations W-8 and W-9 of §98.233), then the monitoring period must begin before February 1 of the reporting year and must not end before December 1 of the reporting year. The end of one monitoring period must immediately precede the start of the next monitoring period for the next reporting year. All production days must be monitored and all venting accounted for.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 22827, Apr. 25, 2011; 76 FR 59540, Sept. 27, 2011; 76 FR 80586, Dec. 23, 2011; 78 FR 25395, May 1, 2013; 79 FR 70410, Nov. 25, 2014; 80 FR 64291, Oct. 22, 2015; 81 FR 86514, Nov. 30, 2016]

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§98.235 Procedures for estimating missing data.

Except as specified in §98.233, whenever a value of a parameter is unavailable for a GHG emission calculation required by this subpart (including, but not limited to, if a measuring device malfunctions during unit operation or activity data are not collected), you must follow the procedures specified in paragraphs (a) through (i) of this section, as applicable.

(a) For stationary and portable combustion sources that use the calculation methods of subpart C of this part, you must use the missing data procedures in subpart C of this part.

(b) For each missing value of a parameter that should have been measured quarterly or more frequently using equipment including, but not limited to, a continuous flow meter, composition analyzer, thermocouple, or pressure gauge, you must substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, you must use the first quality-assured value obtained after the missing data period as the substitute data value. A value is quality-assured according to the procedures specified in §98.234.

(c) For each missing value of a parameter that should have been measured annually, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.

(d) For each missing value of a parameter that should have been measured biannually (every two years), you must conduct the estimation or measurement activity for those sources as soon as possible in the subsequent calendar year if the estimation or measurement was not made in the appropriate year (first year of data collection and every two years thereafter), until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used to alternate or postpone subsequent biannual emissions estimations or measurements.

(e) For the first 6 months of required data collection, facilities that become newly subject to this subpart W may use best engineering estimates for any data that cannot reasonably be measured or obtained according to the requirements of this subpart.

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that acquire new sources from another facility that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

(g) Unless addressed in another paragraph of this section, for each missing value of any activity data, you must substitute data value(s) using the best available estimate(s) of the parameter(s), based on all applicable and available process or other data (including, but not limited to, processing rates, operating hours).

(h) You must report information for all measured and substitute values of a parameter, and the procedures used to substitute an unavailable value of a parameter per the requirements in §98.236(bb).

(i) You must follow recordkeeping requirements listed in §98.237(f).

[79 FR 70410, Nov. 25, 2014]

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§98.236 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in §98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xvii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Liquids unloading.* Report the information specified in paragraph (f) of this section.

(vi) *Completions and workovers with hydraulic fracturing.* Report the information specified in paragraph (g) of this section.

(vii) *Completions and workovers without hydraulic fracturing.* Report the information specified in paragraph (h) of this section.

(viii) *Onshore production storage tanks.* Report the information specified in paragraph (j) of this section.

(ix) *Well testing.* Report the information specified in paragraph (l) of this section.

(x) *Associated natural gas.* Report the information specified in paragraph (m) of this section.

(xi) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(xii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(xiii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(xiv) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xv) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xvi) *EOR injection pumps.* Report the information specified in paragraph (w) of this section.

(xvii) *EOR hydrocarbon liquids.* Report the information specified in paragraph (x) of this section.

(xviii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(2) *Offshore petroleum and natural gas production.* Report the information specified in paragraph (s) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Transmission storage tanks.* Report the information specified in paragraph (k) of this section.

(iv) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (v) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(ii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(iv) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(v) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(ii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(iii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Storage tanks.* Report the information specified in paragraph (j) of this section.

(vii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(viii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(ix) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(x) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraph (i) of this section.

(b) *Natural gas pneumatic devices.* You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (b)(4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) The total number of devices of each type, determined according to §98.233(a)(1) and (2).

(ii) If the reported value in paragraph (b)(1)(i) of this section is an estimated value determined according to §98.233(a)(2), then you must report the information specified in paragraphs (b)(1)(ii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted.

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device, the estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) of this section were operating in the calendar year ("T_t" in Equation W-1 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(4) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (4) of this section.

(1) Count of natural gas driven pneumatic pumps.

(2) Average estimated number of hours in the calendar year the pumps were operational ("T" in Equation W-2 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(4) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(d) *Acid gas removal units.* You must indicate whether your facility has any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. If your facility contains any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant, then you must report the information specified in paragraphs (d)(1) and (2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (vi) of this section for each acid gas removal unit.

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) Total feed rate entering the acid gas removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million cubic feet per year.

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in §98.233(d).

(iv) Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in §98.233(d)(11). If any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO_2, in metric tons $CO_{2,}$ that was recovered and transferred outside the facility under subpart PP of this part.

(v) Annual CO_2 emissions, in metric tons CO_2, from the acid gas removal unit, calculated using any one of the calculation methods specified in §98.233(d) and as specified in §98.233(d)(10) and (11).

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) and (B) of this section.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual volume of gas vented from the acid gas removal unit, in cubic feet.

(ii) If you used Calculation Method 3 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (D) of this section.

(A) Indicate which equation was used (Equation W-4A or W-4B).

(B) Annual average volumetric fraction of CO_2 in the natural gas flowing out of the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(C) Annual average volumetric fraction of CO_2 content in natural gas flowing into the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(D) The natural gas flow rate used, as specified in Equation W-4A of this subpart, reported as either total annual volume of natural gas flow into the acid gas removal unit in cubic feet at actual conditions; or total annual volume of natural gas flow out of the acid gas removal unit, as specified in Equation W-4B of this subpart, in cubic feet at actual conditions.

(iii) If you used Calculation Method 4 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (L) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Natural gas feed temperature, in degrees Fahrenheit.

(C) Natural gas feed pressure, in pounds per square inch.

(D) Natural gas flow rate, in standard cubic feet per minute.

(E) Acid gas content of the feed natural gas, in mole percent.

(F) Acid gas content of the outlet natural gas, in mole percent.

(G) Unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(H) Exit temperature of the natural gas, in degrees Fahrenheit.

(I) Solvent pressure, in pounds per square inch.

(J) Solvent temperature, in degrees Fahrenheit.

(K) Solvent circulation rate, in gallons per minute.

(L) Solvent weight, in pounds per gallon.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day, glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day, and dehydrators that use desiccant. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3).

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in §98.233(e)

(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Dehydrator feed natural gas flow rate, in million standard cubic feet per day, determined by engineering estimate based on best available data.

(iii) Dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (*e.g.,* natural gas pneumatic, air pneumatic, or electric).

(vi) Dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripper gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating, in hours.

(xi) Temperature of the wet natural gas, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas, in pounds per square inch gauge.

(xiii) Mole fraction of CH_4 in wet natural gas.

(xiv) Mole fraction of CO_2 in wet natural gas.

(xv) Whether any dehydrator emissions are vented to a vapor recovery device.

(xvi) Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes. If any emissions are vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(1)(xvi)(A) through (C) of this section for these emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator, calculated according to §98.233(e)(6).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator, calculated according to §98.233(e)(6).

(C) Annual N_2O emissions, in metric tons N_2O, for the dehydrator, calculated according to §98.233(e)(6).

(xvii) Whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes. If any emissions are not routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(1)(xvii)(A) and (B) of this section for those emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1), and, if applicable, (e)(5).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1) and, if applicable, (e)(5).

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day (as specified in §98.233(e)(2)), you must report the information specified in paragraphs (e)(2)(i) through (v) of this section for the entire facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device.

(iii) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were vented to each type of control device.

(iv) Whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (D) of this section.

(A) The total number of dehydrators venting to a flare or regenerator firebox/fire tubes.

(B) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(C) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(D) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(v) For dehydrator emissions that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in §98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (iv) of this section for glycol dehydrators, and report the information under this paragraph for dehydrators that use desiccant.

(ii) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(iii) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(f) *Liquids unloading.* You must indicate whether well venting for liquids unloading occurs at your facility, and if so, which methods (as specified in §98.233(f)) were used to calculate emissions. If your facility performs well venting for liquids unloading and uses Calculation Method 1, then you must report the information specified in paragraph (f)(1) of this section. If the facility performs liquids unloading and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts.

(i) Sub-basin ID.

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and well tubing diameter and pressure group ID.

(iii) Plunger lift indicator.

(iv) Count of wells vented to the atmosphere for the sub-basin/well tubing diameter and pressure group.

(v) Percentage of wells for which the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time wells were vented (sum of "T_p" from Equation W-7A or W-7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells in the sub-basin/well tubing diameter and pressure group.

(viii) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to §98.233(f)(1).

(ix) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(x) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) Well ID number of tested well.

(B) Casing pressure, in pounds per square inch absolute.

(C) Internal casing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (E) of this section for each individual well using a plunger lift that was tested during the year.

(A) Well ID number.

(B) The tubing pressure, in pounds per square inch absolute.

(C) The internal tubing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in §93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in (f)(2)(i) through (x) of this section. Report information separately for each calculation method.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

(ii) Calculation method.

(iii) Plunger lift indicator.

(iv) Number of wells vented to the atmosphere.

(v) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells.

(vi) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable.

(vii) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).

(viii) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).

(ix) For wells without plunger lifts, the average internal casing diameter, in inches.

(x) For wells with plunger lifts, the average internal tubing diameter, in inches.

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

(3) Number of completions or workovers in the sub-basin and well type combination category.

(4) Calculation method used.

(5) If you used Equation W-10A of §98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of "$T_{p,i}$" and sum of "$T_{p,s}$" values used in Equation W-10A of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour (average of "$FR_{s,p}$" values used in Equation W-12A of §98.233), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W-12C of §98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil ("GOR_p" in Equation W-12C of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the gas to oil ratio for the well and the well ID number for the well.

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels ("V_p" in Equation W-12C of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W-10B of §98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin ("$FV_{s,p}$" in Equation W-10B of §98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin ("$FR_{p,i}$" in Equation W-10B of §98.233).

(iii) The well ID number for which vented natural gas volume was measured.

(7) Annual gas emissions, in standard cubic feet ("$E_{s,n}$" in Equation W-10A or W-10B).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) If the well emissions were vented to a flare, then you must report the total N_2O emissions, in metric tons N_2O.

(h) *Completions and workovers without hydraulic fracturing.* You must indicate whether the facility had any gas well completions without hydraulic fracturing or any gas well workovers without hydraulic fracturing, and if the activities occurred with or without flaring. If the facility had gas well completions or workovers without hydraulic fracturing, then you must report the information specified in paragraphs (h)(1) through (4) of this section, as applicable.

(1) For each sub-basin with gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and without flaring.

(ii) Number of well completions that vented gas directly to the atmosphere without flaring.

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to the atmosphere as used in Equation W-13B).

the atmosphere as used in Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all "V_p" used in Equation W-13B of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (vii) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and with flaring.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas vented to a flare during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to a flare from Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all "V_p" from Equation W-13B of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vii) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(3) For each sub-basin with gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and without flaring.

(ii) Number of workovers that vented gas to the atmosphere without flaring.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (v) of this section.

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and with flaring.

(ii) Number of workovers that flared gas.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in §98.233(h)(2).

(v) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in §98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or

onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in §98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each “equipment or event type” (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the “equipment or event type” (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

(i) Total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable “N” from Equation W-14A or Equation W-14B of this subpart, for all unique physical volumes for the equipment or event type).

(ii) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to §98.233(i)(2)(iii).

(iii) Annual CH_4 emissions for the equipment or event type, in metric tons CH_4, calculated according to §98.233(i)(2)(iii).

(2) *Report by flow meter.* If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to §98.233(i)(3), then you must report the information specified in paragraphs (i)(2)(i) and (ii) of this section for the facility.

(i) Annual CO_2 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CO_2 (the sum of all CO_2 mass emission values calculated according to §98.233(i)(3), for all flow meters).

(ii) Annual CH_4 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CH_4, (the sum of all CH_4 mass emission values calculated according to §98.233(i)(3), for all flow meters).

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of §98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of §98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized oil API gravity, in degrees.

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(ix) The number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.

(x) The number of atmospheric tanks.

(xi) An estimate of the number of atmospheric tanks, not on well-pads, receiving your oil.

(xii) If any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, then you must report the information specified in paragraphs (j)(1)(xii)(A) through (E) of this section.

(A) The number of atmospheric tanks that control emissions with vapor recovery systems.

(B) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(C) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(D) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks equipped with vapor recovery systems.

(E) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks equipped with vapor recovery systems.

(xiii) If any atmospheric tanks at your facility vented gas directly to the atmosphere without using a vapor recovery system or without flaring, then you must report the information specified in paragraphs (j)(1)(xiii)(A) through (C) of this section.

(A) The number of atmospheric tanks that vented gas directly to the atmosphere without using a vapor recovery system or without flaring.

(B) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere.

(C) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere.

(xiv) If you controlled emissions from any atmospheric tanks at your facility with one or more flares, then you must report the information specified in paragraphs (j)(1)(xiv)(A) through (D) of this section.

(A) The number of atmospheric tanks that controlled emissions with flares.

(B) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with one or more flares.

(C) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with one or more flares.

(D) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with one or more flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of §98.233(j). Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The number of wells with gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(F) The number of wells without gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of §98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of §98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of §98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of §98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares.

(E) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares.

(3) If you used Calculation Method 1 or Calculation Method 2 of §98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

(i) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the "T_n" values used in Equation W-16 of this subpart).

(iii) Annual CO_2 emissions, in metric tons CO_2, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(iv) Annual CH_4 emissions, in metric tons CH_4, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(k) *Transmission storage tanks.* You must indicate whether your facility contains any transmission storage tanks. If your facility contains at least one transmission storage tank, then you must report the information specified in paragraphs (k)(1) through (3) of this section for each transmission storage tank vent stack.

(1) For each transmission storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the transmission storage tank vent stack.

(ii) Method used to determine if dump valve leakage occurred.

(iii) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to §98.233(k)(2).

(iv) Indicate if there is a flare attached to the transmission storage tank vent stack.

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

(i) Method used to measure the leak rate.

(ii) Measured leak rate (average leak rate from a continuous flow measurement device), in standard cubic feet per hour.

(iii) Duration of time that the leak is counted as having occurred, in hours, as determined in §98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii), and the vent stack vented to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (vi) of this section.

(i) Method used to measure the leak rate.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in §98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from flaring gas, calculated according to §98.233(k)(5).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from flaring gas, calculated according to §98.233(k)(5).

(vi) Annual N_2O emissions, in metric tons N_2O, that resulted from flaring gas, calculated according to §98.233(k)(5).

(l) *Well testing.* You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (4) of this section, as applicable.

(1) If you used Equation W-17A of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(2) If you used Equation W-17A of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (viii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(viii) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(l).

(3) If you used Equation W-17B of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(4) If you used Equation W-17B of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vii) of this section.

(i) Number of wells tested in calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(vii) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(l).

(m) *Associated natural gas.* You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented or flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (8) of this section for each sub-basin.

(1) Sub-basin ID and a list of well ID numbers for wells for which associated gas was vented or flared.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the "GOR" values used in Equation W-18 of this subpart).

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of "$V_{p,q}$" used in Equation W-18 of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of "SG" values used in Equation W-18 of §98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (iii) of

this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(m)(3) and (4).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (iv) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(m)(5).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(m)(5).

(iv) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(m)(5).

(n) *Flare stacks.* You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (12) of this section for each flare stack at your facility, and for each industry segment applicable to your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(2) Indicate whether the flare stack has a continuous flow measurement device.

(3) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(4) Volume of gas sent to the flare, in standard cubic feet ("V_s" in Equations W-19 and W-20 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare ("Z_u" in Equation W-19 of this subpart).

(6) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(7) Mole fraction of CH_4 in the feed gas to the flare ("X_{CH4}" in Equation W-19 of this subpart).

(8) Mole fraction of CO_2 in the feed gas to the flare ("X_{CO2}" in Equation W-20 of this subpart).

(9) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W-20 of this subpart).

(10) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W-19 of this subpart).

(11) Annual N_2O emissions, in metric tons N_2O (refer to Equation W-40 of this subpart).

(12) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then you are not required to report N_2O and CH_4 emissions for the flare stack.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (xiv) of this section for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in not-operating-depressurized-mode.

(iv) Indicate whether the compressor was measured in operating-mode.

(v) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate which, if any, compressor sources are routed to a flare.

(viii) Indicate which, if any, compressor sources have vapor recovery.

(ix) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed and associated dates.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i)(A) through (C) of this section.

(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(i) of this section.

(B) Centrifugal compressor source (wet seal, isolation valve, or blowdown valve).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in §98.233(o)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in §98.233(o)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in §98.233(o)(2) or (4) are conducted, report the information specified in paragraph (o)(3)(i) of this section. If the calculation specified in §98.233(o)(6)(ii) is performed, report the information specified in paragraph (o)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (o)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-23 was used to calculate emissions in Equation W-22, report the information specified in paragraphs (o)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-23).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-23).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(o)(3) or (5) are conducted, report the information specified in paragraphs (o)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(o)(3)(ii) and (o)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Number of centrifugal compressors that have wet seal oil degassing vents.

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with wet seal oil degassing vents.

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (xiv) of this section for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) Indicate whether the compressor was measured in operating-mode.

(vi) Indicate whether the compressor was measured in standby-pressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate which, if any, compressor sources are routed to a flare.

(x) Indicate which, if any, compressor sources have vapor recovery.

(xi) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed and associated dates.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i)(A) through (C) of this section.

(A) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(B) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (p)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in §98.233(p)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in §98.233(p)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in §98.233(p)(2) or (4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the calculation specified in §98.233(p)(6)(ii) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (p)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-28 was used to calculate emissions in Equation W-27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section

(A) The compressor mode-source combination.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-28).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-28).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(p)(3) or (5) are conducted, report the information specified in paragraphs (p)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(p)(3)(ii) and (p)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Number of reciprocating compressors.

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors.

(q) Equipment leak surveys. For any components subject to or complying with the requirements of §98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (v) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iii) Except for onshore natural gas processing facilities and natural gas distribution facilities, indicate whether any equipment components at your facility are subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter. Report the indication per facility, not per component type.

(iv) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with §98.233(q) according to §98.233(q)(1)(iv) for any equipment components at your facility.

(v) Report each type of method described in §98.234(a) that was used to conduct leak surveys.

(2) You must indicate whether your facility contains any of the component types subject to or complying with §98.233(q) that are listed in §98.232(c)(21), (d)(7), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero ("0") for the information required according to paragraphs (q)(2)(ii) through (v) of this section.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year ("x_p" in Equation W-30 of this subpart for the component type).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of "$T_{p,z}$" from Equation W-30 of this subpart for the component type).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W-30 (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W-30 (for surveyed components only).

(3) Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraphs (q)(3)(i) through (viii) and, if applicable, (q)(3)(ix) of this section.

(i) Number of above grade transmission-distribution transfer stations surveyed in the calendar year.

(ii) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year (“$Count_{MR,y}$” from Equation W-31 of this subpart, for the current calendar year).

(iii) Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of “$T_{w,y}$” from Equation W-31 of this subpart, for the current calendar year).

(iv) Number of above grade transmission-distribution transfer stations surveyed in the current leak survey cycle.

(v) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle (sum of “$Count_{MR,y}$” from Equation W-31 of this subpart, for all calendar years in the current leak survey cycle).

(vi) Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours (average of “$T_{w,y}$” from Equation W-31 of this subpart, for all years included in the leak survey cycle).

(vii) Meter/regulator run CO_2 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CO_2 per operational hour of all meter/regulator runs (“$EF_{s,MR,i}$” for CO_2 calculated using Equation W-31 of this subpart).

(viii) Meter/regulator run CH_4 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CH_4 per operational hour of all meter/regulator runs (“$EF_{s,MR,i}$” for CH_4 calculated using Equation W-31 of this subpart).

(ix) If your natural gas distribution facility performs equipment leak surveys across a multiple year leak survey cycle, you must also report:

(A) The total number of meter/regulator runs at above grade transmission-distribution transfer stations at your facility (“$Count_{MR}$” in Equation W-32B of this subpart).

(B) Average estimated time that each meter/regulator run at above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run (“$T_{w,avg}$” in Equation W-32B of this subpart).

(C) Annual CO_2 emissions, in metric tons CO_2, for all above grade transmission-distribution transfer stations at your facility.

(D) Annual CH_4 emissions, in metric tons CH_4, for all above grade transmission-distribution transfer stations at your facility.

(r) *Equipment leaks by population count.* If your facility is subject to the requirements of §98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable.

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W-32A of §98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W-32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type and geographic location.

(ii) Total number of the emission source type at the facility ("$Count_e$" in Equation W-32A of this subpart).

(iii) Average estimated time that the emission source type was operational in the calendar year, in hours ("T_e" in Equation W-32A of this subpart).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(v) Annual CH_4 emissions, in metric tons CH_4, for the emission source type.

(2) Natural gas distribution facilities must also report the information specified in paragraphs (r)(2)(i) through (v) of this section.

(i) Number of above grade transmission-distribution transfer stations at the facility.

(ii) Number of above grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(iii) Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations ("$Count_{MR}$" in Equation W-32B of this subpart).

(iv) Average estimated time that each meter/regulator run at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("$T_{w,avg}$" in Equation W-32B of this subpart).

(v) If your facility has above grade metering-regulating stations that are not above grade transmission-distribution transfer stations and your facility also has above grade transmission-distribution transfer stations, you must also report:

(A) Annual CO_2 emissions, in metric tons CO_2, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(B) Annual CH_4 emissions, in metric tons CH_4, from above grade metering regulating stations that are not above grade transmission-distribution transfer stations.

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

(i) Calculation method used.

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W-1B and W-1C to this subpart for which equipment leak emissions are calculated using the methodology in §98.233(r).

(A) An indication of whether the facility contains the major equipment type.

(B) If the facility does contain the equipment type, the count of the major equipment type.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEMRE study.

(1) Annual CO_2 emissions, in metric tons CO_2.

(2) Annual CH_4 emissions, in metric tons CH_4.

(3) Annual N_2O emissions, in metric tons N_2O.

(t) [Reserved]

(u) [Reserved]

(v) [Reserved]

(w) *EOR injection pumps.* You must indicate whether CO_2 EOR injection was used at your facility during the calendar year and if any EOR injection pump blowdowns occurred during the year. If any EOR injection pump blowdowns occurred during the calendar year, then you must report the information specified in paragraphs (w)(1) through (8) of this section for each EOR injection pump system.

(1) Sub-basin ID.

(2) EOR injection pump system identifier.

(3) Pump capacity, in barrels per day.

(4) Total volume of EOR injection pump system equipment chambers, in cubic feet (“V_v” in Equation W-37 of this subpart).

(5) Number of blowdowns for the EOR injection pump system in the calendar year.

(6) Density of critical phase EOR injection gas, in kilograms per cubic foot (“R_c” in Equation W-37 of this subpart).

(7) Mass fraction of CO_2 in critical phase EOR injection gas (“GHG_{CO2}” in Equation W-37 of this subpart).

(8) Annual CO_2 emissions, in metric tons CO_2, from EOR injection pump system blowdowns.

(x) *EOR hydrocarbon liquids.* You must indicate whether hydrocarbon liquids were produced through EOR operations. If hydrocarbon liquids were produced through EOR operations, you must report the information specified in paragraphs (x)(1) through (4) of this section for each sub-basin category with EOR operations.

(1) Sub-basin ID.

(2) Total volume of hydrocarbon liquids produced through EOR operations in the calendar year, in barrels (“V_{hl}” in Equation W-38 of this subpart).

(3) Average CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel under standard conditions (“S_{hl}” in Equation W-38 of this subpart).

(4) Annual CO_2 emissions, in metric tons CO_2, from CO_2 retained in hydrocarbon liquids produced through EOR operations downstream of the storage tank (“$Mass_{CO2}$” in Equation W-38 of this subpart).

(y) [Reserved]

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by §98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xviii), (a)(8)(i), or (a)(9)(xii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or

internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) and (ii) of this section for each unit type.

(i) The type of combustion unit.

(ii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. If your facility contains: External fuel combustion units with a rated heat capacity greater than 5 mmBtu/hr; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers, then you must report the information specified in paragraphs (z)(2)(i) through (vi) of this section for each combustion unit type and fuel type combination.

(i) The type of combustion unit.

(ii) The type of fuel combusted.

(iii) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(z)(1) and (2).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(z)(1) and (2).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(z)(1) and (2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (ii) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (C) of this section for the basin as a whole.

(A) The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

(B) The quantity of gas produced in the calendar year for sales, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced in the calendar year for sales, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (M) of this section for each unique sub-basin category.

(A) State.

(B) County.

(C) Formation type.

(D) The number of producing wells at the end of the calendar year and a list of the well ID numbers (exclude only those wells permanently taken out of production, *i.e.,* plugged and abandoned).

(E) The number of producing wells acquired during the calendar year and a list of the well ID numbers.

(F) The number of producing wells divested during the calendar year and a list of the well ID numbers.

(G) The number of wells completed during the calendar year and a list of the well ID numbers.

(H) The number of wells permanently taken out of production (*i.e.,* plugged and abandoned) during the calendar year and a list of the well ID numbers.

(I) Average mole fraction of CH_4 in produced gas.

(J) Average mole fraction of CO_2 in produced gas.

(K) If an oil sub-basin, report the average GOR of all wells, in thousand standard cubic feet per barrel.

(L) If an oil sub-basin, report the average API gravity of all wells.

(M) If an oil sub-basin, report average low pressure separator pressure, in pounds per square inch gauge.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.

(i) The total quantity of gas handled at the offshore platform in the calendar year, in thousand standard cubic feet, including production volumes and volumes transferred via pipeline from another location.

(ii) The total quantity of oil and condensate handled at the offshore platform in the calendar year, in barrels, including production volumes and volumes transferred via pipeline from another location.

(3) For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.

(i) The quantity of natural gas received at the gas processing plant in the calendar year, in thousand standard cubic feet.

(ii) The quantity of processed (residue) gas leaving the gas processing plant in the calendar year, in thousand standard cubic feet.

(iii) The cumulative quantity of all NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The cumulative quantity of all NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH_4 in natural gas received.

(vi) Average mole fraction of CO_2 in natural gas received.

(vii) Indicate whether the facility fractionates NGLs.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

(ii) Number of compressors.

(iii) Total compressor power rating of all compressors combined, in horsepower.

(iv) Average upstream pipeline pressure, in pounds per square inch gauge.

(v) Average downstream pipeline pressure, in pounds per square inch gauge.

(5) For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.

(i) The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(6) For LNG import equipment, report the quantity of LNG imported in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported in the calendar year, in thousand standard cubic feet.

(8) For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.

(i) The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of LNG withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(v) The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(vi) The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.

(vii) The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet.

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

(bb) For any missing data procedures used, report the information in §98.3(c)(8) except as provided in paragraphs (bb)(1) and (2) of this section.

(1) For quarterly measurements, report the total number of quarters that a missing data procedure was used for each data element rather than the total number of hours.

(2) For annual or biannual (once every two years) measurements, you do not need to report the number of hours that a missing data procedure was used for each data element.

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4) (iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in §98.3(b) introductory text.

[79 FR 70411, Nov. 24, 2014, as amended at 80 FR 64291, Oct. 22, 2015; 81 FR 86515, Nov. 30, 2016]

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§98.237 Records that must be retained.

Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by §98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

(e) The records required under §98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

(f) For each time a missing data procedure was used, keep a record listing the emission source type, a description of the circumstance that resulted in the need to use missing data procedures, the missing data provisions in §98.235 that apply, the calculation or analysis used to develop the substitute value, and the substitute value.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 70424, Nov. 25, 2014]

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§98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.,* an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Associated gas venting or flaring means the venting or flaring of natural gas which originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. This does not include venting or flaring resulting from activities that are reported elsewhere, including tank venting, well completions, and well workovers.

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Compressor mode means the operational and pressurized status of a compressor. For a centrifugal compressor, “mode” refers to either operating-mode or not-operating-depressurized-mode. For a reciprocating compressor, “mode” refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, “source” refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and wet seal oil degassing vents. For reciprocating compressors, “source” refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see §98.7).

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and -pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to −260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Manifolded compressor source means a compressor source (as defined in this section) that is manifolded to a common vent that routes gas from multiple compressors.

Manifolded group of compressor sources means a collection of any combination of manifolded compressor sources (as defined in this section) that are manifolded to a common vent.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow, or both, in the natural gas distribution industry segment. At least one meter, at least one regulator, or any combination of both on a single run of piping is considered one meter/regulator run.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in §98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reduced emissions completion means a well completion following hydraulic fracturing where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions completion may occur.

Reduced emissions workover means a well workover with hydraulic fracturing (*i.e.,* refracturing) where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions workover may occur.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and *Residue Gas Compression* mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids (with or without gas) and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight gas reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T-D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch; and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

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.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 63794, Oct. 24, 2014; 79 FR 70424, Nov. 25, 2014; 80 FR 64296, Oct. 22, 2015]

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Table W-1A to Subpart W of Part 98—Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Table W-1A to Subpart W of Part 98—Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service[1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors—All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
Western U.S.	
Population Emission Factors—All Components, Gas Service[1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3

Population Emission Factors—All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1]For multi-phase flow that includes gas, use the gas service emissions factors.

[2]Emission Factor is in units of “scf/hour/device.”

[3]Emission Factor is in units of “scf/hour/pump.”

[4]Hydrocarbon liquids greater than or equal to 20°API are considered “light crude.”

[5]“Others” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

[6]Hydrocarbon liquids less than 20°API are considered “heavy crude.”

[7]Emission factors are in units of “scf/hour/mile of pipeline.”

[80 FR 64297, Oct. 22, 2015]

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Table W-1B to Subpart W of Part 98—Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				

Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64298, Oct. 22, 2015]

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Table W-1C to Subpart W of Part 98—Default Average Component Counts For Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

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Table W-1D to Subpart W of Part 98—Designation Of Eastern And Western U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah

	Washington
	Wyoming

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Table W-1E to Subpart W of Part 98—Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	**If you survey using Method 21 as specified in §98.234(a)(7)**
Leaker Emission Factors—All Components, Gas Service[1]		
Valve	4.9	3.5
Flange	4.1	2.2
Connector (other)	1.3	0.8
Open-Ended Line[2]	2.8	1.9
Pressure Relief Valve	4.5	2.8
Pump Seal	3.7	1.4
Other[3]	4.5	2.8
Leaker Emission Factors—All Components, Light Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0
Leaker Emission Factors—All Components, Heavy Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0

[1]For multi-phase flow that includes gas, use the gas service emission factors.

[2]The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[3]"Others" category includes any equipment leak emission point not specifically listed in this table, as specified in §98.232(c)(21) and (j)(10).

[4]Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

[5]Hydrocarbon liquids less than 20°API are considered "heavy crude."

[81 FR 86515, Nov. 30, 2016]

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Table W-2 to Subpart W of Part 98—Default Total Hydrocarbon Emission Factors for Onshore Natural Gas Processing

Onshore natural gas processing plants	Emission factor (scf/hour/ component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1]Valves include control valves, block valves and regulator valves.

[76 FR 80592, Dec. 23, 2011]

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Table W-3A to Subpart W of Part 98—Default Total Hydrocarbon Leaker Emission Factors for Onshore Natural Gas Transmission Compression

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—Compressor Components, Gas Service		
Valve[1]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter or Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors—Non-Compressor Components, Gas Service		
Valve[1]	6.42	4.12
Connector	5.71	3.66
Open-Ended Line	11.27	7.22
Pressure Relief Valve	2.01	1.29
Meter or Instrument	2.93	1.88
Other[2]	4.1	2.63

[1]Valves include control valves, block valves and regulator valves.

[2]Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in §98.232(e)(8).

[81 FR 86516, Nov. 30, 2016]

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Table W-3B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Table W-3B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf/hour/component)
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86516, Nov. 30, 2016]

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Table W-4A to Subpart W of Part 98—Default Total Hydrocarbon Leaker Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—Storage Station, Gas Service		
Valve[1]	14.84	9.51
Connector (other)	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors—Storage Wellheads, Gas Service		
Valve[1]	4.5	3.2
Connector (other than flanges)	1.2	0.7
Flange	3.8	2.0
Open-Ended Line	2.5	1.7
Pressure Relief Valve	4.1	2.5
Other[2]	4.1	2.5

[1]Valves include control valves, block valves and regulator valves.

[2]Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in §98.232(f)(6) and (8).

[81 FR 86517, Nov. 30, 2016]

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Table W-4B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Table W-4B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86517, Nov. 30, 2016]

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Table W-5A to Subpart W of Part 98—Default Methane Leaker Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—LNG Storage Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other[1]	1.77	0.99
Leaker Emission Factors—LNG Storage Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[3]	4.1	2.63

[1]"Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2]Valves include control valves, block valves and regulator valves.

[3]"Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(g)(6) and (7).

[81 FR 86518, Nov. 30, 2016]

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Table W-5B to Subpart W of Part 98—Default Methane Population Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86518, Nov. 30, 2016]

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Table W-6A to Subpart W of Part 98—Default Methane Leaker Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—LNG Terminals Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other[1]	1.77	0.99
Leaker Emission Factors—LNG Terminals Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[3]	4.1	2.63

[1]"Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2]Valves include control valves, block valves and regulator valves.

[3]"Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(h)(7) and (8).

[81 FR 86518, Nov. 30, 2016]

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Table W-6B to Subpart W of Part 98—Default Methane Population Emission Factors for LNG Import and Export Equipment

Table W-6B to Subpart W of Part 98—Default Methane Population Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1]Emission Factor is in units of "scf/hour/compressor."

[81 FR 86518, Nov. 30, 2016]

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Table W-7 to Subpart W of Part 98—Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission factor (scf/hour/component)
Leaker Emission Factors—Transmission-Distribution Transfer Station[1] Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors—Below Grade Metering-Regulating station[1] Components, Gas Service[2]	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population Emission Factors—Distribution Mains, Gas Service[3]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors—Distribution Services, Gas Service[4]	
Unprotected Steel	0.19

Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Excluding customer meters.

[2] Emission Factor is in units of “scf/hour/station.”

[3] Emission Factor is in units of “scf/hour/mile.”

[4] Emission Factor is in units of “scf/hour/number of services.”

[76 FR 80594, Dec. 23, 2011]

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