



ARKANSAS
Department of Environmental Quality

AUG 31 2016

Mitch Colvin, Environmental Engineer
Lion Oil Company
1000 McHenry Drive
El Dorado, AR 71730

Dear Mr. Colvin:

The enclosed Permit No. 0868-AOP-R10 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 9/29/2015.

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 0868-AOP-R10 for the construction and operation of equipment at Lion Oil Company shall be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

A handwritten signature in black ink, appearing to read "Stuart Spencer", is written over a horizontal line.

Stuart Spencer
Associate Director, Office of Air Quality

Enclosure: Final Permit

RESPONSE TO COMMENTS

LION OIL COMPANY PERMIT #0868-AOP-R10 AFIN: 70-00016

On May 27, 2015 the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted on behalf of the facility. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Comment 1: The dates for two applications are reversed in the Statement of Basis.

Response: The dates were changed.

Comment 2: The reviewers notes of the Statement of Basis states the Title V application lacked emission data for ammonia and hydrogen sulfide, and as a result those pollutants were removed from the draft permit. The application included emission estimates in the calculations. Please add ammonia and hydrogen sulfide to the permit in Plantwide Condition 7.

Response: Lion Oil provided updated emission rate tables. The pollutants were added to the permit and the notes in the Statement of Basis were updated.

Comment 3: The Statement of Basis under Ambient Air Evaluations includes only reserved under item 8 and does not address criteria pollutants. Lion Oil requests that ADEQ officially note that an air quality analysis was not required for this renewal. Lion Oil proposes the following language: "No air quality analysis required for criteria pollutants because the modifications incorporated into the permit with this renewal are below minor modification levels."

Response: The section is reserved to discuss a NAAQS evaluation when conducted. Since there was no evaluation conducted, the section is left as-is. The proposed language is irrelevant. The Statement of Basis was not changed.

Comment 4: The table of contents is not very descriptive, and the size of the permit makes it difficult to locate the group of conditions applicable to each unit at the refinery. Expand the table of contents to provide additional detail on the location to each type of emission unit.

Response: Each section of the Specific Conditions was added to the table of contents.

Comment 5: This comment requested the removal of references in the Source Descriptions to equipment removed from service and historical reference descriptions that are out of date “upon completion of” for example.

Response: The process description was updated.

Comment 6: Throughout the permit, outdated and obsolete emissions limitations, monitoring, and recordkeeping requirements have not been removed when newer requirements have been added to the permit to replace them. For example, SN-804 is required to comply with a lb/hour NO_x emissions limit (FHR 1) and demonstrate compliance by limiting the total annual BTUs (FHR 3), and keeping records of the annual BTUs (FHR 4). The same source is required to comply with a lb/MMBtu emission limit (FHR 8) and monitor compliance through CEMs (FHR 12).

The newer, more stringent lb/MMBtu emissions limits have been incorporated into the permit, but the older lb/hour limit and its associated methods for demonstrating compliance should be removed. This results in Lion Oil having multiple emissions limits for the same source, for the same pollutant, and often with different monitoring requirements. The older limits are no longer applicable and should be removed. See attached table for specific conditions where this occurs.

If ADEQ cannot remove the lb/hour emissions limits, the limits need to be identified as unenforceable. The "emissions summary" table at the beginning of the permit contains lb/hr emissions limits that are not enforceable. These limits should be sufficient for ADEQ's purposes. Alternatively, if the obsolete lb/hour limits remain in the source sections, the permit should state expressly that they are unenforceable and the monitoring, recordkeeping and reporting requirements should be removed or likewise identified as unenforceable.

Remove NO_x limit for SN-804 from FHR 1; See FHR 8;
Remove NO_x limits for SN-803, 805, 808, 810, and 841 from FHR 1; See FHR 9;
ASP 1 -Remove lb/hour emissions limits that are redundant of NSPS, subpart J;
Remove VRU 1-VRU 4;
Remove WW 4-WW 7

Response: It is unclear if the “newer” emission limits are in fact more stringent. These new limits are long term averages of 30 days or more and in the short term may exceed stated lb/hr emission rates. Therefore it cannot be assumed that the “new” emission rates are stricter than the lb/hr emission rates.

Under Regulation 19.404, application for a permit shall contain such information as required on the nature and amounts of federally regulated air pollutants to be emitted by the stationary source. ADEQ requires short term emission rates on permits. Short term limits have been provided in the permit application by the facility and re-stated in the permit.

The limits are enforceable.

Comment 7: In many or most instances, there is no Clean Air Act applicable requirement that requires a lb/hour emission limit, but Regulation 19 (the SIP) is cited as the applicable authority for the limit. The lb/hour emission limits without underlying CAA applicable requirements should be removed from the permit in favor of the applicable requirements- PSD limits, NSPS, MACT, NESHAP, etc.

Remove lb/hr emissions limits from FHR 1; FCCU 1, SRP 1; BOI 1; FLA 1; CCR 1; ASP 1; AIR 1; VRU 1; CRP 1; WW 4; LEAK 1.

Response: Arkansas Regulation 19 is an applicable requirement. The referenced PSD, NSPS, MACT, NESHAP, etc. limits often do not place a limit on overall emissions or on a short term basis. No limits were removed.

Comment 8: There are inconsistent and redundant references to the NSPS, MACT, NESHAP standards throughout the permit. In some instances, a section of the permit will contain a summary of the standards, for example, a summary of the NSPS subpart J requirements. In other instances, there is a reference in the section to complying with NSPS subpart J, which is summarized in PW 11.

The regulations (effective on the date of permit issuance) are appended to the permit. Therefore, Lion Oil does not believe a summary of the regulations should be included in the permit. The summary quickly becomes outdated due to changes to the regulations or changes to operations. Therefore, neither Lion Oil nor ADEQ rely on the summary for purposes of determining compliance. In fact, PW 13 prohibits reliance on the summaries as they may be outdated.

Accordingly, Lion Oil would like all summaries of NSPS, MACT, and NESHAP requirements to be removed from the permit. If the summaries cannot be removed, Lion Oil would like all of the summaries to be included in the Plantwide conditions (like PW 9, 10, 11, and 12) and not in the specific conditions so that it is clear that the FHR 12 prohibition on relying on the summaries applies.

SRP 8, BOI 13, AIR 7, WW 7, LEAK 4, LEAK 5, TANK 9

Response: A Title V permit is required to contain all applicable requirements. In order for both Lion Oil and the Department to be aware of exactly what are the requirements of a particular regulation those conditions must be in the permit. The requirements were not removed from the permit. If operational conditions at the facility have changed, Lion Oil should have addressed those changes in an application for modification of the permit before making the change. Any issues would be addressed in the permitting process. If a federal rule changes, they are noticed prior to promulgation and typically given a compliance date in the future. Lion Oil would have ample time to submit an application to modify the permit.

The Department tries to place the conditions outlining the requirements of a federal regulation where they make it the easiest on the facility to determine compliance for a source. If a federal regulation applies to the whole facility or a large number of sources, those requirements are

usually placed in the Plantwide Conditions. If those regulations apply to only a source or a group of sources, the conditions are usually placed with the source.

Comment 9: There are repeated references throughout the permit to the requirement to operate all CEMs in accordance with the Department's CEMs conditions. Since this requirement applies to all CEMs in operation at the refinery, the requirement should be placed in a plantwide condition, rather than in various sections throughout the permit. This change will reduce redundancy in the permit and therefore the annual compliance certification.

Please delete FHR 10; FHR 11, FCCU 7, SRP 6, BOI 11, and VRU 6, and incorporate a plantwide condition to operate all CEMs in accordance with the Department's CEMs conditions.

Response: The conditions which are requested to be deleted are the requirements to install and operate a CEM not just a requirement to operate with the CEMs conditions. The requirements and conditions for each source are placed in the section for that source. The conditions were not deleted.

Comment 10: Throughout the permit, there are requirements to comply with a 5% opacity standard. Reg.18.501 is cited as the regulatory authority for the requirement. Reg.18.501 establishes a 40% opacity standard for sources installed before 1972, a 20% opacity standard for sources installed after 1972, and a 20% opacity standard for wood, coal, or oil fired boilers installed after 1972, except that emissions of opacity greater than 20%, but not exceeding 60%, will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60 minute period, provided such emissions will not be permitted more than three (3) times during any 24 hour period. Reg.18.501 permits ADEQ to establish lower limits "due to control requirements or control apparatus, corresponding emission limitations and/or applicable national standards." There is no indication in the permit or permit history, which explains the lower opacity standards for sources singled out in Lion Oil's permit.

If a more stringent opacity standard applies to the source through a federal standard, for example, NSPS, subpart J, the Lion Oil should be required to comply with the more stringent standard in accordance with subpart J, but the Reg.18.501 opacity standard should not be ratcheted down to match the more stringent regulatory standard.

Please correct the opacity standards to those listed in the state regulations for FHR 5; FCCU 3; BOI 6; BOI 7; ASP 3; AIR 3; CRP 3; BFP 4, ENG 3, ENG 4.

Response: Four of the Specific Conditions, FCCU 3, BOI 7, CRP 3 and ENG 3, requested to be corrected had 20% opacity limits and are required under Reg.19.501. That regulation applies and is no explanation of why those conditions or how those conditions should be corrected are provided in the comment. Those Specific Conditions were not changed.

As the comment states, Reg.18.501 allows the Department to establish lower opacity limits. The sources, FHR 5; BOI 6, ASP 3; AIR 3; and ENG 4, listed all burn natural gas or refinery gas. Those sources should not have a visible emission or opacity under proper operation. Therefore, they were given a 5% opacity and compliance is to burn natural gas or refinery gas. The

comment does not show why the sources would have any visible emission under normal proper operation.

The comment mentions where a federal standard applies the 18.501 limit should not be ratcheted down. The Department found no federal standard for opacity for the sources in question therefore the Department did not “ratchet down” any opacity standard.

The comment does not show why the opacity limits in the listed conditions are inappropriate or incorrect. No changes to the permit were made.

Comment 11: There are multiple references to ADEQ's address in the permit. One reference to the address in GP-7 is sufficient.

Remove redundant references to ADEQ address in LEAK 3.

Response: The address was removed. Language was added to the condition to submit the required inventory in accordance with General Provision 7.

Comment 12: Certain Consent Decree requirements must be incorporated into this permit so that they may survive termination of the Consent Decree. However, the Consent Decree should not be explicitly referenced in Specific Condition language or listed as the underlying source because the Consent Decree will eventually terminate.

Remove all references to the Consent Decree when embedded in Specific Condition language or referenced as the underlying source.

Response: The Consent Decree is the basis for why the Specific Conditions were placed on the facility in this permit. As long as the Consent Decree is the basis for this permit it should be cited as the reason for those conditions. Even comments on the draft of this permit are based on language changes due to what the Consent Decree states. Whether the Consent Decree is terminated in the future it will still be the basis for why the conditions in this permit were written. The references cannot be removed. No changes to the permit were made.

Comment 13: FHR 8, FHR 9, and FHR 11 contain NO_x emissions limits that are different than the limits in FHR 1. The NO_x limits in FHR 8, FHR 9, and FHR 11 are BACT limits that replace the limits in FHR 1. The table in FHR 1 needs to be updated to contain the correct NO_x emissions limits for these sources or these sources need to be removed from FHR 1 in favor of FHR 8, FHR 9, and FHR 11. The lb/hour emissions limits need to be clarified – that they are based on a 3-hour rolling average basis (per the reference method used to determine compliance). The pound per hour emissions limit cannot be enforceable when there is a more stringent lb/MMBtu limit for the source and the table should reflect that.

Remove SN-803 (See FHR 9); SN-804 (See FHR 12); SN-805 (See FHR 9); SN-808 (See FHR 9); SN-810 (See FHR 9); SN-811 (See FHR 9); SN-842 (See FHR 9)

Response: The emission rates in FHR 1 are based on the application and the information

provided in the calculations and emission rate tables of that application. If those limits are incorrect Lion Oil should submit new emission rate tables and calculations which are correct.

See previous responses for the issue of lb/hr and duplicate and obsolete emission rates.

The requested 3-hour average basis was added.

Comment 14: Need to add provision for NSPS, Subpart Ja applicability.

FHR 7 should specifically identify which sources are subject to NSPS, subpart J. (See Consent Decree Paragraph 17.B.) The Consent Decree also contains the several sources are now subject to NSPS, subpart Ja and not J. A new specific condition needs to be added identifying the Ja affected facilities (SN-805N).

Response: Lion Oil was asked to provide a list of the sources which would be subject to Ja and their requirements. The facility replied the comment was in error and the source SN-805N and others in this section is not subject to Ja. Therefore, a new condition listing Ja sources was not made. Listing all the sources again which would be subject to subpart J is not necessary. The condition FHR 7 specifically states all the sources in listed in condition FHR 1 are subject to subpart J. Based on information provided in the application all the sources in this section are subject to NSPS Subpart J. The only NSPS Subpart Ja sources are in other sections and those sections cover their applicability. No changes to the permit were made.

Comment 15: There are two NO_x limits for SN-804 -- FHR 1 and FHR 8. FHR 8 is more stringent. Therefore, FHR 1 limit should be removed.

Remove SN-804 from FHR 1 and FHR 2. NO_x limit in FHR 8 is more stringent than FHR 1 and monitoring is required in FHR 12 and FHR 13, rather than FHR 2. Strike reference to "consent agreement" (see General Comments). (See Consent Decree Paragraph 16.D. (in part) SN- 804 emissions limits)

Response: See the response to previous comments for a response on the Consent Decree and lb/hr emission rate issue.

Comment 16: Contains more stringent NO_x limit for SN-803, 805, 810, 811, and 842 than in FHR 1.

Remove SN-803, 805, 810, 811, and 842 from FHR 1 and FHR 2 (BTU limits) because the NO_x limits in SC-9 are more stringent and compliance is monitored in accordance with FHR 10 and FHR 11 (not FHR 2 BTU limits). (See Consent Decree Paragraph 16.D. (in part) SN-803, 805, 808, 810, 811, 842 emissions limits; but missing 813, 841, 836 and boilers 1-3)

Response: See previous responses.

Comment 17: NO_x CEMS requirement for SN-811 does not say install, certify, calibrate, maintain and operate; does not mention § 60.11 or appendices A, B, and F as required by CD.

Revise condition (FHR 11) to say "install, certify, calibrate, maintain and operate;" Cite 40 C.F.R. § 60.11 and appendices A, B, and F as required by CD. (See Consent Decree Paragraph 16.C.i. for SN-811)

Response: The Department agrees. The requested change was made.

Comment 18: NO_x CEMS for SN-804 per Consent Decree requirement.

For CEMS does not say install, certify, calibrate, maintain and operate; does not mention §§ 60.11 or appendices A, B, and F as required by Consent Decree. Strike reference to "consent agreement" (see General Comments).

Response: The references to §§ 60.11 or appendices A, B, and F as required by Consent Decree were added. See the response to Comment 12 referenced by this comment for a response on the Consent Decree portion of this comment. The other language was updated.

Comment 19: The NO_x emissions limits in FHR 13 are different than the limits for the same sources in FHR 1 and redundant of the NO_x emissions limits in FHR 8 and FHR 9 for SN-803, SN-804, and SN-805; NO_x limit for SN-804 is same in FHR 8; This provision contains a legal conclusion and not an operating limit and should be moved to the background section of the permit.

Move FHR 13 to Section III: Permit History as it contains legal conclusions, rather than operating limits.

Response: FHR 13 states the following table shall not be exceeded. It lists the BACT control technology required and limits from previous PSD permit. These are applicable limits not legal conclusions. The two limits are applied to the facility on a separate basis. The "more stringent" limits are based upon PSD and BACT. The limits of FHR 1 are based solely on different provisions of Regulation 19.

As FHR 8 and FHR 13 both require an identical NO_x limit for SN-804 the FHR limit was removed and a note saying see FHR 8 was placed in its stead. The limits for SN-803 and 805 in FHR 11 are PM₁₀ limits. The limits in FHR 8 and 9 for those sources are NO_x limits. Those limits are not redundant and both apply to the facility.

Comment 20: Condition requires periodic testing for a unit equipped with a CEMS. Delete FHR 16. There is a CEM on SN-805N per NSPS, subpart Ja.

Response: The condition was removed.

Comment 21: First and second sentences are wholly redundant. Delete first sentence. More specific emission limits for SO₂, PM, CO, and NO_x are stated in FCCU 4. FCCU emissions limits were revised with a December 5, 2014 letter from Mr. Tom Rheaume to Mr. Tom Hammons, but not incorporated into draft permit.

Delete first redundant sentence. Limits other than VOCs in FCCU 1 should be removed because they have been replaced by the limits in FCCU 4. Revise emissions limits to match December 2014 letter if limits are not removed from the permit.

Response: The redundant sentence was removed. The emissions were updated to reflect the December 5, 2014 Minor Modification approval letter and corresponding application.

The limits in FCCU 4 are all concentration limits. Those limits do not provide a mass limitation on the facility. FCCU 4 limits alone would allow unlimited emissions from the source without other limitations so long as the concentration was achieved. Additionally, the FCCU 4 limits do not apply during start up and shut down. FCCU 1 limits are also needed to provide limitations on the facility during start up and shut down. The Department cannot remove the FCCU 1 condition based on the comment.

Comment 22: In the MACT UUU final rule, EPA stated that CO emissions limit in MACT UUU/NSPS was intended to control organic HAP emissions from FCCUs and in the June 30, 2014 "Proposed Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards" rule, EPA concluded that MACT UUU also controls hydrogen cyanide (HCN) emissions from FCCUs. As a result, the agency did not establish numeric limits or impose additional control requirements for organic HAPs or HCN in either rulemaking, but is relying on the CO emissions limit as a "surrogate" for organic HAP and HCN emissions. Lion requests that the permit reflect that Lion Oil's compliance with its CO emissions limit in FCCU 6 b., and referenced in PW 12 b., was intended to and does in fact limit organic HAP and HCN emissions from the FCCU.

Incorporate the following language at the end of FCCU 6b. and PW 12b. Compliance with the CO emissions limit in FCCU 6b. controls organic HAP and HCN emissions from the FCCU. 40 C.F.R. § 63.1565(c)(l).

Response: FCCU 6 is a condition listing the requirements of the NSPS only. The NSPS does not regulate HAP emissions. Its CO limit was not meant to limit HAP emissions.

The MACT condition in PW 12 lists the specific requirements of the MACT. It does not need to explain the reasoning for those limits. The change was not necessary. No changes were made.

Comment 23: Language is not accurate in FCCU 4.

Says Exceptions to the SO₂ limits above ... "Should say, the foregoing limits do not apply during" (See Consent Decree Paragraph 12.B.)

Response: The Department agrees. The language was added.

Comment 24: Malfunction exemption of FCCU 4 does not track the language of the Consent Decree. Should include SSM of either the FCCU or the WGS. Right now it is limited to SSM of the WGS.

Remove "No more than". Add "either the FCCU or" before WGS (See Consent Decree Paragraph 13.B.)

Response: The Department agrees. The language was added.

Comment 25: Slight changes to the language of FCCU 4(c) need to be made to harmonize it with the Consent Decree language.

1-hour averaging period should be 1 hour average basis. Rolling 365-day average should be 365-day rolling average basis. Instead of "exception to the CO limits." It should say the CO limit does not apply during SSM (See Consent Decree Paragraph 14.B.)

Response: The Department agrees. The language was added.

Comment 26: NO_x CEMS requirement for FCCU does not say install, certify, calibrate, maintain and operate; does not mention 60.11, 60.13, or appendices A, B, and F as required by CD. Additionally, FCCU 5 should include the following language from the Consent Decree regarding the use of CEMS to monitor FCCU limits for SO₂ and CO:

"On and after December 31, 2004, the permittee shall use a SO₂ and O₂ CEMS to monitor compliance of the FCCU with "FCCU 4.a." The permittee shall make CEMS and process data available upon demand as soon as practicable. The permittee shall install, certify, calibrate, maintain and operate the CEMS in accordance with the requirements of 40 CFR 60.11, 60.13 and Part 60 appendix A and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. The CEMS will be used to demonstrate compliance with the CO emission limits in FCCU 4.a.

On and after December 31, 2004, the permittee shall use a CO and O₂ CEMS to monitor compliance of the FCCU with "FCCU 4.c." The permittee shall make CEMS and process data available upon demand as soon as practicable. The permittee shall install, certify, calibrate, maintain and operate the CEMS in accordance with the requirements of 40 CFR 60.11, 60.13 and Part 60 appendix A and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. The CEMS will be used to demonstrate compliance with the CO emission limits in FCCU 4.c."

Revise condition to say "install, certify, calibrate, maintain and operate;" Cite 40 CFR 60.11, 60.13 and appendices A, B, and F as required by CD. Insert CEMS language as described. (See Consent Decree Paragraph 11.F.i., but not 11.F .ii.)

Response: The condition was revised to include install, certify, calibrate, maintain, and operate and 40 CFR 60.11, 60.13 and Part 60 appendix A and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. The requirements for SO₂, CO and O₂ CEMS were added. The proposed language was not used. The references to the compliance with limits in FCCU 4 were placed in FCCU 4 referring back to FCCU 5.

Comment 27: FCCU 6 Condition contains a typographical error. Delete first word - "On" -from first sentence.

Response: The Department agrees. The requested change was made.

Comment 28: FCCU 6(a): 27(a) is redundant of 25(b).

Response: As there are no Specific Conditions 25(b) and 27(a) in the draft permit, the Department is assuming FCCU 4 and 6 are being discussed. Those two conditions are limits based upon different requirements. FCCU 4 incorporates limits required by the Consent Decree. FCCU 6 incorporates limits from NSPS Subpart Ja. A source at a facility may be subject to many different emission limits for the same pollutant each with a different basis, Arkansas Regulation, PSD, NSPS, MACT, Lion Oils Consent Decree, etc. The limits are not redundant. No changes to the permit were made.

Comment 29: FCCU 6(b) 27(b) is redundant of 25(c).

Response: As there are no Specific Conditions 25(c) and 27(b) in the draft permit, the Department is assuming FCCU 4 and 6 are being discussed. Those two conditions are limits based upon different requirements. FCCU 4 incorporates limits required by the Consent Decree. FCCU 6 incorporates limits from NSPS Subpart Ja. A source at a facility may be subject to many different emission limits for the same pollutant each with a different basis, Arkansas Regulation, PSD, NSPS, MACT, Lion Oils Consent Decree, etc. The limits are not redundant. No changes to the permit were made.

Comment 30: FCCU 6(c) 27(c) is redundant of 25(a).

Response: As there are no Specific Conditions 25(d) and 27(e) in the draft permit, the Department is assuming FCCU 4 and 6 are being discussed. Those two conditions are limits based upon different requirements. FCCU 4 incorporates limits required by the Consent Decree. FCCU 6 incorporates limits from NSPS Subpart Ja. A source at a facility may be subject to many different emission limits for the same pollutant each with a different basis, Arkansas Regulation, PSD, NSPS, MACT, Lion Oils Consent Decree, etc. The limits are not redundant. No changes to the permit were made.

Comment 31: FCCU 6(d) 27(d) contains a limit for 7-day rolling average not included in 25(d).

Response: As there are no Specific Conditions 25(d) and 27(d) in the draft permit, the Department is assuming FCCU 4 and 6 are being discussed. The comment is correct. Those two conditions are limits based upon different requirements. FCCU 4 incorporates limits required by the Consent Decree. FCCU 6 incorporates limits from NSPS Subpart Ja. A source at a facility may be subject to many different emission limits for the same pollutant each with a different basis, Arkansas Regulation, PSD, NSPS, MACT, Lion Oils Consent Decree, etc. The limits are not redundant. No changes were made to the permit.

Comment 32: FCCU 6(f) initial testing already conducted. Delete requirement for initial testing.

Response: The Department agrees the requested change was made.

Comment 33: FCCU 6i (ii) [fifth full paragraph of p. 46, begins with "The permittee shall performance evaluations ...] is missing the word "conduct". There are many redundancies between FCCU 6 (h), (i), (j), and (k) regarding performance specs for monitors.

Please correct the condition by inserting "conduct." Combine FCCU 6(h), (i), (U), and (k) into a single condition applicable to several constituents.

Response: "Conduct" was inserted. The conditions were not merged. Each condition section specifies the requirements for a different CEM. These conditions vary and each has different requirements. While each is similar, they are not redundant.

Comment 34: FCCU 6(p) Requirements of excess emission report redundant for FCCU and SRU (e.g., SC-40(b)-(e)). Please delete redundant requirements.

Response: Each of those conditions requires reports for the source to which it applies. As each discusses a different source they are not redundant though each source requires similar reports. Also each requirement for a source is in the Permit section for that source to make compliance for each source easier to determine. No changes were made.

Comment 35: FCCU 8 Says the FCCU is subject to MACT II and see PC 11 for requirements. Move to process description, as this is not an operating limit.

Response: The condition requires no action. To ease showing compliance for this source, the condition only references the Plantwide Condition which outlines the federal requirements to which the source is also subject. This is to keep at least a reference to other requirements where the other compliance conditions are listed. No changes were made.

Comment 36: FCCU 11 With a December 5, 2014 letter from Mr. Tom Rheume to Mr. Tom Hammons, ADEQ increased the allowable coke burn rate to 11,700 lb of coke per hour. This change was not incorporated into the permit.

Revised the allowable coke burn rate to 11,700 lb/hr.

Response: The condition was revised according to the Minor Modification approval letter and the corresponding application.

Comment 37: SRP 7 Largely redundant of PW 12. Delete SRP 7. If left in, "summarize" should be "summarized."

Response: The Condition requires no action. To ease showing compliance for this source, the condition only references the Plantwide Condition which outlines the federal requirements to which the source is also subject. This is to keep at least a reference to other requirements where the other compliance conditions are listed. No changes were made.

Comment 38: SRP 8 Subpart J for the SRU - CD requirement. Keep the first sentence. Keep the first sentence. Move the summary of the requirements of subpart J to the Plantwide Conditions. See General Comments above re: regulatory summaries.

Response: No changes were made. See Response to General Comment referenced.

Comment 39: SRP 9 is a new condition in the draft R10 permit with no underlying regulatory basis. Delete this condition.

Response: The condition has been deleted. It had an inappropriate regulation citation but was placed in the permit due to Lion Oil not including H₂S emissions on its emission rate tables for the source. H₂S emissions are now included in the permit; the condition is no longer necessary.

Comment 40: SN-821a, 821b, and 821c (p 54) Revised source description to reflect present tense for the boilers, 821a, 821b, and 821c as they are currently in operation.

Response: The Department agrees. The requested change was made.

Comment 41: The boilers are subject to NSPS, subparts J and Db. The lb/hour emission limits in BOI 1 are not applicable requirements and should be removed. In addition, the boilers' NO_x emission limits conflict with the NO_x emission limits in SC-51 of the R9 Permit.

Delete lb/MMBtu limits in the table in BOI 1. Applicable lb/MMBtu limits are in SC-51 of the R9 Permit. Other applicable requirements are in BOI 12 and BOI 13.

Response: See previous responses. The limits were not removed.

The lb/MMBtu limits in conditions BOI 1 were not necessary and were removed as requested.

Comment 42: BOI 5 This is a plantwide condition. There is only one refinery fuel gas system. Remove to PC.

Response: This condition is used to show compliance with the maximum heat input requirements of the boilers not of the refinery gas system. It is in the proper place. The condition was not moved.

Comment 43: BOI 8 When burning fuel oil, the boilers are subject to NSPS, subpart Db. Remove BOI 8.

Response: The comment does not explain how being subject to an NSPS relates to the opacity limits of this Condition. This condition is to show compliance with the opacity limit in BOI 7. As the NSPS requires the operation of a COMs condition BOI 8 compliance mechanism is changed to show compliance using the COMs required in BOI 12c.

Comment 44: BOI 10 When burning fuel oil, the boilers are subject to NSPS, subpart Db.
Remove BOI 10

Response: The comment does not explain how being subject to an NSPS relates to this condition. This condition is referenced as a method of compliance for the criteria emission limits BOI 1. The comment provides no insight as to how the NSPS shows compliance with these unrelated limits. No changes to the permit were made.

Comment 45: SC-51 of the R9 permit was deleted. Boilers emissions limit conflicts with SC-41 Return SC-51 to the R10 draft. Delete conflicting limits in BOI 1. (See Consent Decree Paragraph 16.D. 3- hour average for boilers)

Response: Former Specific Condition 51 was replaced. The Consent Decree specifically requires the facility comply with this limit. The comment does not explain why the limits in BOI 1 were conflicting. The two conditions were placed in the permit due to different basis each. The Department sees no conflict between the limits and without explanation no limits can be deleted.

Comment 46: SN-822 and SN-823 The Flares are NSPS, Subpart Ja affected facilities. Update all references in the source description and specific conditions to reflect that the flares are subject to NSPS, Subpart Ja.

Response: The reference was added. The additional requirements for Ja for the flares were also added.

Comment 47: The Flares are NSPS, Subpart Ja affected facilities (FLA 6). The lb/hour emissions limits in FLA 1 are not applicable requirements and should be removed.

Remove lb/hour emission limits for flares and FLA 7 and FLA 8, which are methods for demonstrating compliance with the lb/hour emission limits.

Response: See previous responses to this issue.

Comment 48: FLA 4 Section 60.18 of the NSPS, subpart A is not inclusive. Broaden to include all of NSPS subpart A. (See Consent Decree Paragraph 19.A.)

Response: This condition was placed on the facility to ensure compliance with the emission limits under Arkansas Regulation and only included the specific operation requirements for a flare in § 60.18. A separate condition was added to incorporate the all operation requirement of Subpart A required by the Consent Decree.

Comment 49: FLA 5 Another Subpart of NSPS, subpart A, Section 60.18. Combine with FLA 4, NSPS Subpart A requirements.

Response: This condition was placed on the facility to ensure compliance with the emission limits under Arkansas Regulation and only included the specific operation requirements for a

flare in § 60.18. Subpart A as a whole contains many requirements beyond the limited scope of this condition; therefore, a separate condition was added to incorporate the all operation requirement of Subpart A required by the Consent Decree. The conditions were not combined.

Comment 50: FLA 6 The Flares are NSPS, Subpart Ja affected facilities. Revise FLA 6 to reference NSPS Ja.

Response: The Department agrees. The requested change was made.

Comment 51: The CCR is an NSPS, subpart UUU affected facility (CCR 6). The lb/hour emissions limits in CCR 1 are not applicable requirements and should be removed.

Delete the lb/hour emission limits in CCR 1.

Response: See previous response to this issue.

Comment 52: CCR 4 This condition limits the amount of catalyst recirculated at SN-831. Emissions limits for SN-831 are no longer tied to the amount of catalyst recirculated in the CCR.

Lion requests that ADEQ delete this condition. Lion proposes to calculate emissions and maintain records of emissions on a 12- month rolling basis to verify - compliance with the current permit limits.

Response: The Department agrees. The condition was removed. It was not necessary to require a calculation of emissions.

Comment 53: CCR 5 This condition requires record keeping for the amount of catalyst recirculated at SN-831. Emissions limits for SN-831 are no longer tied to the amount of catalyst recirculated in the CCR. Lion proposes to calculate emissions and maintain records of emissions on a 12- month rolling basis to verify - compliance with the current permit limits.

Response: The Department agrees. The Condition was removed. It was not necessary to require a calculation of emissions.

Comment 54: SN-832 description of tank heaters includes T-56, T-99, T-111, T-354, and T-548 that have been removed from service or no longer are a source of emissions. Remove T-56, T-99, T-111, T-354, and T-548 from the source description.

Response: The Department agrees. The requested change was made.

Comment 55: ASP 1 This source has lb/hour emission limits that are redundant of the NSPS, subpart J limits. The lb/hour emission limits that are redundant of the limits in NSPS, subpart J should be removed.

Response: See previous response to this issue.

Comment 56: ASP 5 Typographical error. First sentence - "is" should be "are"

Response: The Department agrees. The requested change was made.

Comment 57: AIR 5 Initial testing already conducted. Remove requirement for initial testing

Response: The Department agrees. The requested change was made.

Comment 58: AIR 6 Condition contains requirements for catalytic converters. Delete this condition. This unit is regulated by MACT Subpart ZZZZ.

Response: The comment does not explain how MACT ZZZZ relates to AIR 6. However, MACT ZZZZ does contain adequate requirements for operation of the catalyst on these sources to make the condition unnecessary. The condition was removed.

Comment 59: VRU 1-VRU 4 There is no applicable requirement that establishes a lb/hour emission limit for the loading rack. Rather, the loading rack is subject to MACT, subpart CC. Remove references to the lb/hour emissions limits (VRU 1) and the methods for demonstrating compliance with them in VRU 2 – VRU 4.

Response: See previous response to this issue.

Comment 60: VRU 6 All but first sentence redundant of other SCs requiring compliance with MACT CC and CEMS requirements. Remove all but first sentence in VRU 6.

Response: Condition VRU 6 is only one sentence long, and does not require a CEM. The comment may mean VRU 7. However, there was no other provision to install a CEM or how to operate that CEM found for this source other than VRU 7 and the comment does not explain which condition VRU 7 is redundant with. No changes were made.

Comment 61: HOL 3 References a PAL. Probably not a PAL, but a cap. See CT I - does not refer to this as a PAL. Change reference from PAL to cap.

Response: HOL 3 does not reference a PAL. HOL 4 does and was changed to bubble to match language elsewhere. The Department is unsure of the reference to CT 1 as it is an unrelated cooling tower condition.

Comment 62: HOL 5 This condition requires record keeping to ensure that PSD review is not triggered. NSR rules require record keeping for a period of 10 years. This equipment has been in service for over 10 years. Any increase in emissions that may occur at this equipment would be unrelated to the modifications that triggered this condition. Please delete this condition.

Response: HOL 5 does not reference the language in the comment. HOL 6 does and the Department agrees it is no longer necessary and it was removed.

Comment 63: HOL 6 This condition requires record keeping to ensure that PSD review is not triggered. NSR rules require record keeping for a period of 10 years. This equipment has been in service for over 10 years. Any increase in emissions that may occur at this equipment would be unrelated to the modifications that triggered this condition. Please delete this condition.

Response: HOL 6 does not reference the language in the comment. HOL 7 does and the Department agrees it is no longer necessary and it was removed.

Comment 64: (SN-851/SN- SN-851) The wastewater treatment section of the permit includes a process description and specific conditions for an "old" wastewater collection system and a "new" wastewater collection system (SN-851a). SN-851a is now in service, and SN-851 is obsolete.

Please delete all references to SN-851, references to a "new" and "old" system, as well as WW 1, WW 2, and WW 3.

Response: The Department agrees. The requested change was made.

Comment 65: During review of the facility in development of the Title V renewal application, Lion discovered two cooling towers that had not previously been included in the permit. The two cooling towers are part of the wastewater treatment plant, and are used to cool wastewater prior to treatment and after treatment, before discharge from the facility. VOC emissions for the towers were already accounted for in the wastewater emissions estimates.

Please update the process description for SN-851a to include these two cooling towers.

Response: The Department agrees. The requested change was made.

Comment 66: WW 4-WW 6 There is no applicable requirement that establishes a pound per hour emission limit for the WW collection system. Once the source is subject to NSPS, Subpart QQQ, Subpart QQQ compliance replaces the lb/hour limits and methods for demonstrating compliance with the lb/hour limits. Remove WW 4-WW 6.

Response: See previous response to this issue.

Comment 67: The Department was notified in a July 21, 2014, letter that the wastewater collection system project is complete. Delete WW 8.

Response: The Department agrees. The requested change was made.

Comment 68: The Department was notified in a July 21, 2014, letter that the wastewater collection system project is complete. Therefore, WW 9 is obsolete. Delete WW 9.

Response: The Department agrees. The requested change was made.

Comment 69: An application to rebuild Cooling Tower 6 was submitted on Towers (p. 84) 4/18/2013, but does not appear to have been incorporated. Update permit to reflect Cooling Tower 6 application.

Response: The Department agrees. The requested change was made.

Comment 70: The limit for the total amount of water circulated at the #3, 5, 6, 7, and 8 cooling is incorrect. The limit for the total amount of water circulated at the #3, 5, 6, 7, and 8 cooling towers shall be limited to 51.5 billion gallons per consecutive twelve month period.

Response: The Department agrees. The requested change was made.

Comment 71: SN-854 (page Remove reference to lb/hour emissions limits in source 86) description. Add reference to MACT EEEE (reference 4/5/2012 crude unloading application). Emission limits do not belong in the source description and are not appropriate for this source. In addition, the limits are different in the source description and LEAK 1. Add a reference to MACT EEEE applicability for components associated with crude oil unloading.

Response: The reference to the limits in the Source Description was removed.

Comment 72: Emission limit for SN-854 is 680.1 lb/hr in the table; however, the preceding source description says all fugitive emissions from the facility (including Tier II fugitives) continue to be subject to the 676.4 lb/hr emission limit for SN-854. There is no applicable requirement that supports a lb/hour emission limit for these sources. Instead, these sources are subject to NSPS and MACT/NESHAP fugitive emissions limits. Add reference to MACT EEEE (reference 4/5/2012 crude unloading application).

LEAK 1 lb/hour emission limit should be removed. If the lb/hour emission limits are not removed, GGG, VV, and CC should be removed as methods for demonstrating compliance with the lb/hour limits. Otherwise, if Lion Oil violates one requirement of GGG/VV ICC, it would technically exceed the lb/hour emission limit. Compliance with the lb/hour emission limit is demonstrated through the annual emissions inventory. Add a reference to MACT EEEE applicability for components associated with crude oil unloading.

Response: See previous response to this issue.

Comment 73: See LEAK 1. There should not be a lb/hour emission limits for LEAK 3 this source. This source is regulated under GGG/VV. Remove LEAK 2 and LEAK 3 as methods for demonstrating compliance with the lb/hour emissions limits because a lb/hour emissions limit is not an applicable requirement of the Clean Air Act.

Response: See previous response to this issue.

Comment 74: LEAK 5(f) So that the summary does not have to be edited repeatedly, the permit should reflect that Lion Oil should comply with §§ 60.482-4 as applicable.

Remove statement that Lion Oil does not have any pressure relief devices in gas/vapor service and instead require compliance for pressure relief devices if applicable.

Response: LEAK 5(f) was referenced in the comment. LEAK 6(f) seems to be appropriate and was edited as requested.

Comment 75: MACT EEEE requirements were not incorporated with submittal condition of the crude unloading application in 2012. Incorporate applicable MACT EEEE requirements (reference 4/5/2012 crude unloading application).

Response: The Loading Rack and other sources subject to MACT EEEE were consolidated and the requirements added.

Comment 76: Title of section listing SNs should include SN 856A, the asphalt tanks. Additionally, the following tanks have been or will be demolished and should be removed from the list of tanks in service: T-3, T-22, T-50, T-58, T-70, T-71, T-72, T-73, T-74, T-76, T-96, T-97, T-99, T-111, T-145, T-170, T-171, T-173, T-190, T-240, T-244, T-310, T-311, T-312, T-313, T-314, T-315, T-319, T-320, T-321, T-322, T-323, T-325, T-326, T-327, T-328, T-329, T-331, T-332, T-333, T-335, T-336, T-337, T-338, T-339, T-340, T-354, T-410, T-413, T-414, T-432, T-512, T-524, T-525, T-530, T-765. T-324 has been renamed T-394. Finally T-191 (installed in 2009 with a 144,607 bbl capacity) and T-192 (installed in 2008 with a 137,068 bbl capacity) have been inadvertently deleted from this list and should be replaced onto the list of tanks.

Add SN-856A to header. Update the list of tanks as shown.

Response: The changes were made. T-512 should be T-521 and it was removed also.

Comment 77: List of tanks is inaccurate. The tanks listed above in the comment on the process description should be deleted from TANK 3. Additionally, T-700, T-70lt, T-702t, and T-703t should be included in the tank list under TANK 3 (Reference the 12/14/2011 biodiesel storage application). T-119 (diesel storage tank) vapor pressure limit was not revised as noted in 4/17/2013 permit application. Update list of tanks as shown in comment on tanks process description above. Add in T-700, T-70lt, T-702t, and T-703t. Revise T-119 vapor pressure limit to 0.75

Response: The Department agrees. The changes were made.

Comment 78: SN-863 was never installed and should be removed from the permit. Remove BFP 1- BFP 5.

Response: The Department agrees. The changes were made.

Comment 79: DS-028- Naphtha Loading/Unloading Rack has been replaced by SN-869 (Tank 536 Truck Loading Rack) Remove DS 1- DS 3.

Response: The Department agrees. The changes were made.

Comment 80: "Manufacture's" should be "manufacturer's" DS 5 and DS 7 should be combined. Delete DS 5 and change DS 7 to say "Lion Oil shall comply with all emission standards specified in 60.4204(b). Compliance with this condition will be shown by compliance with the manufacturer's written instructions or procedures for the operation of SN-864 and SN-865." "Over the entire life of the engine" should be removed because as written, the requirement is to always operate in accordance with the manufacturer's written instructions. "Over the life of the engine" suggests that you could only measure compliance by determining whether the engine has been operated its entire life in accordance with the manufacturer's instructions.

Response: Condition DS 5 and 7 are separate as they are two separate requirements of the NSPS. "Over the life of the engine" is wording from the NSPS applicable and cannot be removed. The condition was reworded with the exact phrasing from the NSPS to avoid any confusion.

Comment 81: The process description incorrectly states that the loading rack is vapor balanced. Note in the process description that the initial notification and notification of compliance status have been submitted as required by MACT EEEE. Revise to note that the loading rack emissions are routed to a fuel gas system or back into a process as specified in 40 CFR 63, Subpart SS. Incorporate note that notifications submitted as required.

Response: The process description describes a process not whether notifications have been submitted. That note was not added. The language about the routing of gasses was added.

Comment 82: Lion has submitted the initial notification and notification of compliance status required by MACT EEEE. Therefore, no additional notification requirements apply. Delete TRL 1.d.

Response: The Department agrees. The requested change was made.

Comment 83: TRL 1.e.i. should read "table 11" instead of "table II."

Response: The Department agrees. The requested change was made.

Comment 84: References to "this section" need to be revised to read MACT EEEE. As written, this condition reads as if it refers to sections of the permit, not sections of the MACT. This ambiguous language creates problems for the facility and inspection staff during inspections, ultimately requiring each to revisit regulatory applicability determinations during each inspection. Replace "this section" with the appropriate regulatory citations.

Response: The Department agrees. The permit was searched for all instances "this section" and replaced all found with the reference to the appropriate section of Federal Regulation.

Comment 85: With the R10 draft permit, ADEQ consolidated the list of HAPs to a single HAP limit. In doing so, emissions limits for ammonia and hydrogen sulfide were lost.

Add back ammonia and hydrogen sulfide emissions limits as presented in Lion's Title V renewal permit application.

Response: Lion Oil did not include ammonia or H₂S in their emission rate tables of the permit application and were asked twice about their inclusion. Lion Oil provided the appropriate forms after the comment period and they were incorporated into the permit.

Comment 86: BWON TAB <10MG. Needs to be updated. Lion Oil has submitted its annual TAB report indicating that its TAB is greater than 10 MG and is preparing a compliance plan to comply with the 6BQ compliance option. Revise PW 9a. as follows: "The permittee has identified itself as having a total annual benzene quantity from facility waste of equal to or greater than 10 Mg/yr. The facility shall follow any applicable requirements of § 61.342(e). [40 C.F.R. § 61.342(e)]"

Response: The change was made.

Comment 87: "The facility" is not subject to MACT CC - certain affected sources are subject. Change to "Certain affected sources at the refinery are subject to..."

Response: The change was made. The exact requested wording was not used.

Comment 88: Subpart J applies to sources other than those listed in FHR 1. PW 11 should list all of the sources that are subject to Subpart J or none.

Response: The reference to FHR 1 in PW 11 was deleted.

Comment 89: PC-18 of the R9 permit was deleted from the draft R 10 permit, and should be restored in the R1 permit. SN-809 and SN-810 appear on both tables 5 and 6 of the permit shield indicating that they are subject to subpart J (table 5) and not subject to subpart J (table 6). They are affected facilities subject to NSPS subpart J.

Restore PC-18 from the R9 permit in the R10 permit. The Consent Decree caused all then existing heaters and boilers to become subject to NSPS, subpart J. Therefore, these heaters should be removed from table 6. See CD ~17.8.

There is an extra comma between SN-842 and SN-944 in Table 5. Table 5 should include the RICE MACT, 40 CFR Part 63, Subpart ZZZZ as an applicable requirement for SN-841A. The tanks identified in Table - 5 are not the only affected sources at the refinery subject to MACT, subpart CC.

Response: This permit is a renewal. The information cannot be carried over from a previous permit. Lion Oil provided the information for a new permit shield and it was added to the permit.

Comment 90: PW 19 should identify all sources that are subject to NSPS subparts A and J in order to fulfill the Consent Decree requirement in 17.B. PW 19 says "should be identified as affected facilities". The permit should say these sources "are" affected facilities. Identify all sources that are subject to NSPS subparts A and J. Revise language as specified.

Response: Instead of listing every source at the facility subject to the NSPS again. The condition was changed to the exact language of the referenced paragraph of the Consent Decree. This would be more consistent with the Consent Decree.

Comment 91: PW 20.b. applies now. Therefore, the forward looking reference to the Consent Decree limit should be removed. Also for clarity, the CO's definitions of Torch Oil and Fuel Oil should be incorporated.

Revise to include a definition Of "Torch Oil": FCCU feedstock or light cycle oil that is combusted in the FCCU regenerator to assist in starting up or restarting the FCCU
Revise to read "Lion Oil shall be permitted to burn Fuel Oil in combustion units provided that emissions from any such units are routed through the FCCU wet gas scrubber " Fuel Oil needs to be defined in this paragraph as "any liquid fossil fuel with sulfur content of $>0.05\%$ by weight"

Response: The definitions were added.

Comment 92: Condition is redundant of SRP 8. Remove PW 21.

Response: SRP 8 outlines the facility's requirements from NSPS Subpart J, which is based on the requirements of the subpart itself. PW 21 states the requirement of the consent decree to comply with the NSPS for this source. The two different reasons for the requirement make this condition not redundant. No changes to the permit were made.

Comment 93: The requirements in PW 22 are not plantwide conditions, but apply to Lion Oil's sulfur plant. Keep, but move to sulfur plant section, after SRP 8. Change "route all emissions" to "continue to route all emissions" to be consistent with the CD and past practices.

Response: While the condition does only refer to SN-844 the condition is in a section which outlines the facility's compliance with the consent decree. The condition was not moved.

Comment 94: Redundant of FLA 6. No longer applies, as NSPS Ja has been triggered for the flares. Delete PW 24.

Response: As NSPS Ja applies the condition is no longer necessary and was removed.

Comment 95: PW 25 These are definitions from the Consent Decree that apply exclusively to PW 26. PW 26 no longer needs to reference the flares, because they have triggered NSPS Ja and are required to comply with the rule's root cause investigation, corrective action and reporting requirements. Therefore the definitions from PW 25 (as to the flares) from the Consent Decree

are no longer necessary. The definition in PW 25.b.ii should remain (defines Tail Gas Incident as to thermal incinerators).

PW 25 and PW 26 should be combined to avoid confusion as to the scope of these definitions. If ADEQ does not want to combine the requirements, it should be clear that they only apply to PW 26. Delete PW 26 a. and

c. (See CD ~20 (1st paragraph); 20.B.i. (as specified therein), 20.E.i. (as specified therein), and 2I).

Response: Plantwide Conditions PW 25 and 26 were merged leaving only the one tail gas incident requirement not directly related to the flares. The definition was merged into the condition to avoid confusion with the two definitions of “tail gas incident” which were in Consent Decree.

Comment 96: References to AG flaring incidents and HC flaring incidents from the Consent Decree are no longer necessary because the flares are both JA affected facilities and will comply with the rule's root cause investigation, corrective action and reporting requirements. PW- 26 should remain as to Tail Gas Incidents meeting the definition in PW 25.b.ii. Remove references to AG flaring incidents and HC flaring incidents. (See CD ~20 (1st paragraph); 20.B.i. (as specified therein), 20.E.i. (as specified therein), and 2I).

Response: Plantwide Conditions PW 25 and 26 were merged leaving only the one tail gas incident requirement not directly related to the flares. The definition was merged into the condition to avoid confusion with the two definitions of “tail gas incident” which were in Consent Decree.

Comment 97: PW 27 Condition is obsolete. Delete condition.

Response: PW 27 is a requirement of the Consent Decree Paragraph 27. Paragraph 24D of the Consent Decree states that those provisions will survive even after the termination of the Consent Decree. The comment does not explain why the condition is obsolete. Based on the lack of justification for removal and the language of the Consent Decree no changes to the permit were made.

Comment 98: PW 28 Condition is obsolete. Delete condition.

Response: PW 28 is a requirement of the Consent Decree Paragraph 27. Paragraph 24D of the Consent Decree states that those provisions will survive even after the termination of the Consent Decree. The comment does not explain why the condition is obsolete. Based on the lack of justification for removal and the language of the Consent Decree no changes to the permit were made.

Comment 99: PW 30 is redundant of PW 12.w., which is a summary of MACT, subpart UUU and captures 63.6(e)(3) specifically. The requirement in PW12.w. is in 63.6(e)(3)(v). Therefore, if ADEQ wants to spell out the SSM report retention requirements in greater detail, it should do so in PW 12. Outside of PW 12, the context for the requirement in PW 30 is unclear in addition to being redundant of PW 12.w.

PW 30 should be removed.

Response: The Condition was unnecessary and was removed.

Comment 100: PW 31 is redundant with PW 23. Delete PW 31.

Response: The Condition was unnecessary and was removed.

Comment 101: Section VII. The insignificant activities list was changed dramatically from, the R9 permit to the R10 draft permit. All category A-2, A-3, and A-4 insignificant and A-4 insignificant activities were deleted, and should be carried over to the R10 permit.

Response: This permit is the renewal permit for the facility. The permittee must apply for all sources and all insignificant activities to be included in the renewal. There is no carry over from previous permits. The permit application only contains information on two insignificant activities and those are included in permit. If Lion Oil wishes to include more activities as insignificant, an administrative amendment should be submitted to include those.

Due to issues with Federal Rules which came into effect after the Department gave notice on the draft permit decision an additional draft permit was issued to address those necessary changes and incorporate the remaining outstanding minor modification for the facility. On May 18, 2016 the Director of the Arkansas Department of Environmental Quality gave notice of a draft permitting decision for the above referenced facility. During the comment period, written comments on the draft permitting decision were submitted on behalf of the facility. The Department's response to these issues follows.

Comment 1: In the Header for the emergency engines "OOC" should read "OCC."

Response: The Department agrees. The requested change was made

Comment 2: Short term rates for SN-870 and 871 should be 0.1 lb/hr for SO₂ and 0.6 lb/hr for VOC.

Response: The Department agrees. The requested change was made.

Comment 3: Lion requests that ADEQ clarify the monitoring, recordkeeping, and reporting associated with the Compliance Plan and Schedule by adding the following language: "The extensions in the Compliance Plan and Schedule include reporting, recordkeeping, and monitoring requirements that derive from the rule requirements for which an extension was granted."

Response: This statement is not true for all the extensions granted. The language was not added.

Comment 4: PW 35 requires Lion to conduct a one-time energy assessment for the units subject to the Boiler MACT. The energy assessment was completed in May 2015. Please revise PW 35 to note that the energy assessment was completed in May 2015.

Response: The facility's compliance inspector can verify the assessment was completed as required. The Department does not wish to state a permit requirement was completed when it hasn't reviewed the assessment. No changes were made.

Comment 5: The insignificant activities list does not include two activities for which Lion has received approval. In a letter from Phillip Murphy to Mitch Colvin dated April 20, 2016, Lion received approval for A-4 and A-9 insignificant activities. Please add these activities upon issuance of the final permit.

Response: The Activities were added.

ADEQ OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0868-AOP-R10

IS ISSUED TO:

Lion Oil Company
1000 McHenry Drive
El Dorado, AR 71730
Union County
AFIN: 70-00016

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

AUG 31 2016

AND

AUG 30 2021

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:



Stuart Spencer
Associate Director, Office of Air Quality

AUG 31 2016

Date

Table of Contents

SECTION I: FACILITY INFORMATION	5
SECTION II: INTRODUCTION	6
Summary of Permit Activity	6
Process Description	6
Regulations	14
Emission Summary	16
SECTION III: PERMIT HISTORY	24
SECTION IV: SPECIFIC CONDITIONS	35
Furnaces, Heaters, and Reboilers.....	35
SN-803, 804, 095, 805N, 806, 808, 810, 811, 812, 813a, 814, 828, 830, 842, 850, 857, 860, 861, 862,.....	35
SN-809 - #7 FCCU Catalyst Regenerator Stack.....	45
ALTERNATE OPERATING SCENARIO - FCCU PORTABLE AIR COMPRESSORS	53
SN-844 - SRP Sulfur Recovery Plant Incinerator.....	54
SN-821a, 821b, 821c - Refinery Boilers (Three Boilers)	57
SN-822 - High Pressure Flare	63
SN-823 - Low Pressure Flares	63
SN-831 -#9 Continuous Catalyst Regenerator (CCR).....	66
SN-832 - 47 Asphalt Tank Heaters	67
SN-841A – G398TA Air Compressor	69
SN-846 - Gasoline/Diesel Loading Rack.....	77
SN-847 - Heavy Oil Loading Racks	79
SN-849 – Stand by Diesel Crude Pump.....	81
SN-851a - Wastewater Collection	83
Cooling Towers.....	86
SN-854 - Fugitive Equipment Leaks	88
SN-858f – Tier 2 Fugitives and Tanks VOC Bubble.....	88
SN-869 - Tank 536 Truck Loading Rack	88
SN-856 - Facility Tanks – Plantwide Bubble	103
856a - Asphalt Tanks	103
SN-858t – Tier 2 Fugitives and Tanks VOC Bubble.....	103
SN-864 and 865	119
Dredge Engine and Booster Pump Engine.....	119
SN-867, 868, 870, and 871	121
OCC Generator	121
IT Generator.....	121
Fire Pump Engines.....	121
SECTION V: COMPLIANCE PLAN AND SCHEDULE	124
SECTION VI: PLANTWIDE CONDITIONS	126
SECTION VII: INSIGNIFICANT ACTIVITIES.....	149
SECTION VIII: GENERAL PROVISIONS	150
Appendix A	
Appendix B	

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

Appendix C
Appendix D
Appendix E
Appendix F
Appendix G
Appendix H
Appendix I
Appendix J
Appendix K
Appendix L
Appendix M
Appendix N
Appendix O
Appendix P
Appendix Q
Appendix R

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
C.F.R.	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO _x	Nitrogen Oxide
PM	Particulate Matter
PM ₁₀	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO ₂	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

SECTION I: FACILITY INFORMATION

PERMITTEE:	Lion Oil Company
AFIN:	70-00016
PERMIT NUMBER:	0868-AOP-R10
FACILITY ADDRESS:	1000 McHenry Drive El Dorado, AR 71730
MAILING ADDRESS:	1000 McHenry Drive El Dorado, AR 71730
COUNTY:	Union County
CONTACT NAME:	Mitch Colvin
CONTACT POSITION:	Environmental Engineer
TELEPHONE NUMBER:	(870) 864-1464
REVIEWING ENGINEER:	Shawn Hutchings
UTM North South (Y):	Zone 15: 3673684.71 m
UTM East West (X):	Zone 15: 530423.62 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Lion Oil Co. owns and operates a petroleum refinery located in El Dorado, Union County, Arkansas. This permit is the Title V renewal for the facility. This renewal incorporates a number of minor modification applications which include adding new tanks, an intermediates truck loading rack, a fire pump engine, and a crude oil unloading rack and incorporates a compliance plan and schedule for recently released sector rules, incorporates the provisions of the Boiler MACT.

Process Description

#1 Crude Unit:

This unit, which included the #1 Crude Topping Furnace (SN-801) and the #1 Crude Vacuum Furnace (SN-802) was removed from service.

#4 Crude Unit:

This unit is designed to separate approximately 65,000 BPD of light straight run gasoline and crude oil into various components of naphtha, gasoline, kerosene, diesel, gas oils and asphalt. Crude entering the unit is preheated using heat exchangers and hot rundown streams from the unit and flashed in the Pre-flash Column to produce gasoline and naphtha. The Pre-flash Column Reboiler (SN-803) is a NSPS Subpart J quality gas fired furnace used to maintain the temperature in the column. Bottoms from the column are heated in the fuel gas fired Atmospheric Topping Furnace (SN-804) prior to distillation at atmospheric pressure. The Atmospheric Column further separates the crude into naphtha, kerosene, diesel, and gas oil. Bottoms from the column are heated in the fuel gas fired Vacuum Furnace (SN-805) prior to vacuum distillation. The Vacuum Column separates the bottoms into gas oil and asphalt products.

#7 Fluid Catalytic Cracking Unit:

This unit is designed to convert approximately 20,000 BPD of gas oil from the refinery crude units and other sources into more useful products. Gas oil entering the unit is first heated to 675°F in the #7 FCCU Furnace (SN-808) which is fired with NSPS Subpart J quality gas and equipped with low NO_x burners. The hot oil is then contacted with a hot (approximately 1350°F) fluidized catalyst which causes the gas oil to crack into lighter products. The catalyst is then separated from the products in the Reactor and returned to the Regenerator. In the Regenerator, coke which has deposited on the catalyst is burned off and the catalyst is recycled. The hot flue gas leaving the Regenerator passes through two (2) sets of cyclones to remove any catalyst fines and is then used to produce steam in the waste heat boiler. The hot gases are then cooled to less than 500°F before exiting the #7 Catalyst Regenerator Stack (SN-809). The light products produced in the reactor are separated in the Fractionator Tower and used for various

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

purposes. The FCCU Catalyst Regenerator Stack (SN-809) is equipped with a wet gas scrubber (WGS) for the control of SO₂ and PM₁₀ emissions.

#8 ULSD Hydrotreater:

The new #8 unit is designed to process diesel, kerosene, gas oil, or light cycle oil. This unit makes ultra low sulfur diesel quality fuel from diesel feedstock by reducing the sulfur content to 15 ppm as mandated by the Tier II diesel sulfur regulations. Light cycle oil, diesel, kerosene, or gas oil is heated in the new Tier II heater (SN-860) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow through a high and low pressure product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The high pressure hydrogen gas stream is passed through an amine absorber to remove hydrogen sulfide gases from the system for sulfur removal in the sulfur recovery plant and/or NaHS unit. The liquid from the low pressure separator is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#9 Unit:

This unit is designed to process approximately 16,000 BPD of naphtha from the crude unit and upgrade it into higher octane products. The process is divided into the Unifiner and Platformer sections.

In the Unifiner section, naphtha is heated in the #9 Hydrotreater Furnace/Reboiler (SN-810) and reacted with hydrogen over a cobalt/molybdenum catalyst to convert the sulfur in the naphtha stream to hydrogen sulfide. The Reactor effluent is passed through the Separator and Stripper to remove the hydrogen and hydrogen sulfide. The Stripper bottoms are sent to the Platformer section for further processing.

In the Platformer section, the Stripper bottoms are heated in the #9 Reformer Furnace (SN-811) and passed over a platinum/iridium catalyst in the Reactor where the naphtha molecules are restructured to form high octane compounds. The Reactor effluent is sent to two (2) Separators where hydrogen is separated from the platformate and recycled. The platformate is then sent to the Stabilizer, heated by the #9 Stabilizer Reboiler (SN-812), where the low molecular weight gases are removed and sent to the Reformer fuel gas system. The bottoms from the Stabilizer are sent to gasoline storage.

The Continuous Catalyst Regeneration (CCR) section of the Platformer allows the unit to increase its yield of high octane product due to increased activity from the catalyst. During a normal operating cycle, platforming catalyst deactivates due to coke laydown. The CCR is a continuous regeneration process that allows the coked catalyst to be continuously regenerated, therefore decreasing downtime required to maintain efficient operation. The #9 Continuous Catalyst Regenerator (SN-831) continuously burns off the coke deposit and restores catalyst activity, selectivity, and stability to essentially fresh catalyst levels.

As a result of the catalytic reforming process, high carbon content coke is deposited on the catalyst. This catalyst is then pneumatically conveyed from the reactor section to the regeneration section of the unit. Coke content on the spent catalyst is typically 4-5%, but at times may be as high as 12%. The catalyst is regenerated with a recirculated gas stream that is typically controlled between 0.9% and 1.1% oxygen. The coke on the catalyst is oxidized and the regenerated catalyst leaves the regeneration zone at less than 0.2% coke. The catalyst then passes to subsequent zones in the regenerator to further condition the catalyst for use in the reactors. This gas leaving the regenerator is approximately 0.35% oxygen. Stoichiometrically, this equates to using approximately 50% excess oxygen in the regeneration process.

#10 Diesel Desulfurization Unit:

This unit uses a heavy cut of FCC gasoline as feed and removes sulfur to levels that will yield overall concentrations of sulfur in Lion Oil's gasoline pool to 30 ppm to meet the Tier II Gasoline sulfur regulations. Heavy FCC gasoline is heated in the #10 hydrotreater furnace/reboiler (SN-813a) and then reacted with hydrogen in the reactor. Bottoms from the reactor flow to the product separator where the unreacted hydrogen is separated from the product and recycled to the reactor. The product then flows to a flash drum where most of the hydrogen sulfide that was formed in the reactor is flashed off and sent to the #17 and #18 units for treatment. The liquid from the flash drum is passed through a stripper to remove any residual hydrogen sulfide before the desulfurized product is sent to storage.

#11 Deasphaltizing Unit:

Asphalt produced directly from the #4 Crude Unit is processed through this unit to separate light hydrocarbons from the asphalt to yield a product suitable for catalytic cracking and at the same time, produce an asphalt with desirable properties. The #11 Unit is designed to process approximately 7,000 BPD of asphalt. Flux from the Crude Units is pumped into the top of the Extraction Tower and a propane/butane solvent is pumped into the bottom of the Extraction Tower. The two materials flow countercurrent to each other in the Extraction Tower. The solvent and deasphalted oil are then sent through a series of Evaporators and a Stripper where the solvent is distilled and condensed for recycle to the Extraction Tower. The deasphalted oil is used as feed to the Catalytic Cracker. Asphalt from the bottom of the Extraction Tower is heated in the #11 Deasphaltizing Furnace (SN-814) and is passed through the Flash Tower and Asphalt Stripper to remove any residual solvent. The asphalt product is then sent to the Asphalt Plant where it is blended with other products.

#12 Distillate Hydrotreater:

This unit is a diesel and gas oil desulfurization unit with a design capacity to process 24,000 BPD. Its purpose is to produce on-road diesel quality fuel to meet the Clean Air Act standards. The light cycle oil from the #7 FCCU and the kerosene and diesel from the #4 Crude Unit is processed to reduce the sulfur content from approximately 2.0 weight percent to less than 0.05 weight percent. The unit is also used to hydrotreat gas oils to remove sulfur from the feed to the #7 FCCU.

The mixed feed flows through the heat exchange train and the #12 Distillate Hydrotreater Furnace (SN-842) before being reacted with hydrogen in the Reactor. The Reactor effluent flows through the heat exchange train with final cooling by an air fin cooler before flowing into the High Pressure Separator where the unreacted hydrogen is separated from the product and recycled to the Reactor. A small portion of the unreacted hydrogen stream is vented to the sour fuel gas system for treatment in the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit.

The liquid product is then flowed to the Low Pressure Separator where some of the hydrogen sulfide which was formed in the Reactor is flashed off and sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The liquid from the Low Pressure Separator then flows through heat exchangers to the Stripper to remove any residual hydrogen sulfide. The liquid from the bottom of the Stripper is then cooled in the heat exchangers and the product air fin cooler before being sent to storage. The Stripper off gas is cooled in an air fin cooler and compressed before being mixed with the High Pressure Separator vent stream and the off gas from the Low Pressure Separator. This combined off gas stream is sent to the #17 Sulfur Recovery Unit and the #18 Sodium Hydrosulfide Unit for treatment. The makeup hydrogen to the unit is supplied from two (2) compressors which also compress the recycled hydrogen and the Stripper off gas. These compressors are driven by electric motors. All emergency releases are routed to the existing refinery flare system.

Boilers:

Lion operates three boilers (SN-821a, SN-821b, SN-821c). The combined heat rating for the three new boilers will be 605 MMBtu/hr. These boilers are to be fired with NSPS Subpart J quality gas. The boilers may burn fuel oil if fuel gas and natural gas are unavailable.

Sour Water Stripper:

The refinery generates numerous water streams from storage tanks and accumulators that contain high concentrations of hydrogen sulfide and ammonia. The Sour Water Stripper (SWS) is a trayed column which is used to steam strip the hydrogen sulfide and ammonia from the sour water streams before the water is discharged into the refinery waste water treatment system. The sour gases that are stripped from the water are directed to a Claus combustor/thermal reactor to recover sulfur in the form of hydrogen sulfide from sour water stripper offgas.

#18 Sodium Hydrosulfide Unit:

Several processes in the refinery produce gases which cannot be reprocessed and sold as liquid propane gas (LPG) or gasoline. These gases are generally methane, ethane, and hydrogen produced from catalytic cracking and the reforming of petroleum fractions. As these light fractions are separated from other heavier gases, hydrogen sulfide is separated with the light gases, making the gas sour. In order to use this gas as fuel for refinery furnaces and boilers, the hydrogen sulfide must be removed to prevent excess SO₂ emissions as the fuel is burned.

The #18 Sodium Hydrosulfide Unit is used to remove the hydrogen sulfide from the fuel gas. The unit removes hydrogen sulfide by contacting the gas with caustic soda to form sodium hydrosulfide which is sold to paper mills to be used as a delignifying agent. The fuel gas leaving the unit then flows to the #17 Unit where it is contacted with amine. This unit removes hydrogen sulfide to below the levels of 40 C.F.R. § 60, Subpart J. The fuel gas is used as fuel in refinery furnaces and boilers. Any SO₂ emissions to the atmosphere are accounted for in the individual emissions for the boilers and furnaces and the Sodium Hydrosulfide Unit is not itself an emission source.

#17 Sulfur Recovery Plant:

The purpose of the Sulfur Recovery Plant is to recover sulfur, up to 100 LTD (long tons per day), as hydrogen sulfide from fuel gas and off-site natural gases from Great Lakes Chemical to meet refinery New Source Performance Standards (NSPS - Subpart J) for process fuel gases (less than 0.1 grains H₂S). In addition, Sour Water Stripper (SWS) off gas can be treated in the Sulfur Recovery Plant. The hydrogen sulfide is converted to a salable elemental sulfur product. The Sulfur Recovery Plant is also used to convert ammonia from SWS off gas to diatomic nitrogen and water. The Sulfur Recovery Plant can be divided into three (3) process units:

- a. Amine Unit consisting of two (2) amine contactors
- b. Sulfur Recovery Unit (SRU) (Claus)
- c. Tail Gas Treating Unit (TGTU)

Sour gas enters the primary amine unit where it is contacted with amine. The amine removes hydrogen sulfide and some carbon dioxide from the sour fuel gas stream. The sweetened gas exits the primary amine unit for distribution throughout the refinery. Hydrogen sulfide and carbon dioxide are stripped from the amine which creates a hydrogen sulfide rich gas (acid gas) stream. The acid gas is then sent to the SRU.

Acid gas from the primary amine unit and recirculated gas from the TGTU, along with SWS off gas, enter the SRU and go directly to the Claus Combustor/Thermal reactor. This is where approximately one-third of the hydrogen sulfide is converted to sulfur dioxide. Ammonia in the SWS off gas is converted to diatomic nitrogen and water at the Claus reactor. The hot vapor products leaving the thermal reactor make several passes through the sulfur condenser and the catalytic reactors. The sulfur condenser separates the condensed sulfur from the vapor and removes it to storage. The catalytic reactors further promote the reaction of hydrogen sulfide and sulfur dioxide to sulfur and water vapor. The remaining gas exits the SRU to the TGTU. The purpose of the TGTU is to recover sulfur from the SRU tail gas. The sulfur compounds are hydrogenated to hydrogen sulfide in the TGTU reactor. The vapor products from the reactor are then cooled and directed to the TGTU amine unit which operates much like the primary amine unit. The amine stripper off gas is recirculated to the SRU feed and the amine absorber off gas is directed to the Sulfur Recovery Plant catalytic incinerator (SN-844). The remaining low concentrations of hydrogen sulfide, carbon monoxide, and hydrogen are combusted in the incinerator.

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

Flares:

The refinery operates a High Pressure Flare (SN-822) and a Low Pressure Flare (SN-823) for disposing of excess combustible gases. These gases result from undetected leaks in operating equipment, upset conditions in the normal operation of a refinery where gases must be vented to avoid dangerously high pressure in operating equipment, plant start-ups, and emergency shutdowns. The flares are identical John Zink "smokeless" flares which use steam aspiration to control visible emissions. In addition to excess refinery gases, each flare burns approximately 1,406 scf/hr of natural gas for the pilot burners.

In conjunction with the flares, the refinery operates a flare gas recovery system (FGRS). The FGRS draws excess flare gases from the flare gas header upstream of a liquid seal vessel and recovers gas that would otherwise be burned in the flares. The capacity of the FGRS is automatically varied to maintain a positive pressure on the flare header upstream from the liquid seal vessel. Maintaining a positive pressure ensures that the air is not drawn into either the flare system or the flare gas recovery system. If the volume of the gas in the flare header exceeds the capacity of the FGRS, the excess gas will vent through the water seal on the FGRS to the flares.

Cellulose Fiber Baghouse:

The refinery operates an asphalt protective coatings unit. Cellulose fibers are received in bags and added to the system via a negative pressure hood and conveyor system. Any exhaust from the system is filtered through the Asphalt Protective Coating Baghouse (SN-807). Based on information submitted by Lion Oil in a letter dated July 25, 2002, this source has been moved to the insignificant activities list.

Truck Loading Racks:

The refinery operates several truck and rail loading racks. Products loaded range from asphalt to propane. The main truck loading rack is an automated bottom loading rack (SN-846) for loading transport trucks with all grades of gasoline and diesel. Emissions from all other loading racks are accounted for in the Heavy Oil Loading Racks (SN-847). Vapors generated at the gasoline/diesel loading rack during the loading operations are routed through a knock-out pot where any free liquids are recovered and the vapors are vented to a vapor recovery unit.

Gas Engine Compressors:

The refinery operates a internal combustion gas compressor engine (SN-841A). The compressor operate on natural gas and is utilized in moving gases within refinery applications. The two JVG compressors (SN-839 and SN-840) have been converted from internal combustion to electrical power, and no longer generate any air emissions. The 8GTL compressor was converted to electric power as well. The KVG and SVG Compressors, SN-834, SN-835, SN-837, and SN-838, have been converted to electrical power and no longer generate air emissions.

Hydrocarbon Storage Tanks:

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

The refinery operates numerous hydrocarbon storage tanks which store products ranging from asphalt to propane.

Steam Superheater Furnace:

The refinery operates two (2) steam turbine driven gas compressors which consume 25,000 pounds per hour of superheated steam. The furnace operates on NSPS Subpart J quality gas and has a design heat input of 10.0 MMBtu/hr.

#5 Alkylation Unit:

There are two (2) 1,500 barrel (BBL) steel tanks which are used for storing 99% sulfuric acid which is used as a catalyst in this unit. The charge to this unit is approximately 6,000 BPD. The acid is diluted to 90% and then pumped to two (2) 2,000 barrel (BBL) spent acid tanks. Two (2) Acid Fume Scrubbers (SN-826 and SN-827) packed with polypropylene saddles are used to scrub any vapors which may be generated from the tanks during loading and transfer operations. These sources (SN-826 and SN-827) have been moved to the insignificant activities list.

Asphalt Rack Steam Heater:

Various grades of asphalt which are used for paving are produced at the refinery. A NSPS Subpart J quality gas fired package boiler rated at 10 MMBtu/hr (SN-828) is used to heat asphalt products during the truck loading operation.

#6 Hydrotreater/Isomerization Unit:

This unit has been installed due to EPA's lead phase down regulation. The unit upgrades light straight run naphtha from the crude unit into a higher octane gasoline. It consists of a hydrotreater section and a penex isomerization section. In the hydrotreater, light straight run naphtha from the crude units is heated in the #6 Hydrotreater Furnace/Reboiler (SN-806) and reacted with hydrogen over a nickel/molybdenum catalyst to convert the sulfur in the light straight run naphtha stream to hydrogen sulfide.

The reactor effluent is passed through the separator and stripper to remove hydrogen and hydrogen sulfide. The stripper bottoms are sent to the penex isomerization section for further processing. Here, the stripper bottoms are heated in the isomerization heater and passed over a platinum catalyst in the reactor where the light straight run naphtha molecules are restructured to form higher octane compounds. The reactor effluent is sent to a separator where hydrogen is separated from the isomerate and recycled. The isomerate is then sent to the stabilizer where the low molecular weight gases are removed through a caustic scrubber and sent to the refinery fuel gas system. The bottoms from the stabilizer are sent to gasoline storage.

Asphalt Tank Heaters:

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

The refinery operates forty-seven (47) asphalt tank heaters (SN-832) which are fired by NSPS Subpart J quality gas.

Wastewater Treatment Plant:

This unit uses a combination of chemical, biochemical, and physical processes to remove pollutants from refinery wastewater before discharging into DeLoutre Creek. The main components of the unit are dual API separators, two (2) equalization tanks and pond, a dissolved air flotation (DAF) unit, a cooling tower, two (2) activated sludge bio-reactors, two (2) clarification tanks, sludge recycle equipment, an aerobic digester, and a sludge thickener. Final effluent filters assure a minimum level of suspended matter in the effluent discharged to DeLoutre Creek.

Final effluent cooling towers cool the effluent prior to discharge. Sludges generated at the Waste Water Treatment Plant are dewatered at the Sludge Management Facilities (SMF) prior to effluent disposal.

Lime Silo:

Lime used in the SMF is stored in a lime silo. This silo is equipped with a baghouse (SN-845) which controls emissions during periods of filling. Based on information submitted by Lion Oil in a letter dated July 25, 2002, the Lime Silo Baghouse (SN-845) has been moved to the insignificant activities list.

Polymer Asphalt Letdown Facility:

This unit, which includes SN-850, is designed to produce a performance graded polymer modified asphalt binder for the asphalt paving industry. The unit consists of a refinery fuel gas-fired heater with a design nominal firing rate of 20 MMBtu/hr based on the HHV, a hot oil circulating pump, a heat exchanger, storage tanks, and loading racks. The hot oil circulates through coils in the storage tanks to maintain the final product in a fluid and transportable state. The heat exchanger is included in the hot oil system to keep the neat asphalt in a fluid state during the PMA blending operations.

Fugitive Emissions from Equipment Leaks:

Fugitive emission sources include leaks of hydrocarbon vapors from process equipment and evaporation of hydrocarbons from open areas, rather than a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, wastewater collection, cooling towers, and oil/water separators.

Miscellaneous Operations:

Catalyst used in the #7 FCCU is stored in two hoppers, which exhaust through the #7 FCCU wet gas scrubber unit and are not emission sources. The hoppers are filled by "sucking" the catalyst

Lion Oil Company
 Permit #: 0868-AOP-R10
 AFIN: 70-00016

into the hoppers. Each of the hoppers is equipped with eductors which reduce the pressure in the hoppers during the filling operation.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective March 14, 2016
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective March 14, 2016
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective March 14, 2016
40 C.F.R. § 60 Subpart Db – <i>Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units</i>
40 C.F.R. § 60 Subpart Dc – <i>Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</i>
40 C.F.R. § 60 Subpart J – <i>Standards of Performance for Petroleum Refineries</i>
40 C.F.R. § 60 Subpart Ja – <i>Standards of Performance for Petroleum Refineries</i>
40 C.F.R. § 60 Subpart Ka – <i>Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984</i>
40 C.F.R. § 60 Subpart Kb – <i>Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984</i>
40 C.F.R. § 60 Subpart QQQ – <i>Standards of Performance for Petroleum Refinery Wastewater Systems</i>
40 C.F.R. § 60 Subpart UU – <i>Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture</i>
40 C.F.R. § 60 Subpart VV – <i>Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry</i>
40 C.F.R. § 60 Subpart GGG – <i>Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries</i>
40 C.F.R. § 60 Subpart IIII – <i>Standards of Performance for Stationary Compression Ignition Internal Combustion Engines</i>
40 C.F.R. §61 Subpart FF – <i>National Emission Standards for Benzene Waste Operations</i>
40 C.F.R. § 63 Subpart CC – <i>National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries</i>
40 C.F.R. § 63, Subpart SS – <i>National Emission Standards for Hazardous Air Pollutants</i>
40 C.F.R. § 63 Subpart EEEE -- <i>National Emission Standards for Hazardous Air Pollutants: Organic Liquid Distribution</i>

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

40 C.F.R. § 63 Subpart UUU – <i>National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units</i>
40 C.F.R. § 63 Subpart LLLLL – <i>National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing</i>
40 C.F.R. § 63 Subpart ZZZZ - <i>National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</i>
40 C.F.R. § 63 Subpart DDDDD <i>National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, commercial, and Institutional Boilers and Process heaters</i>

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	200.4	283.8
		PM ₁₀	200.4	283.8
		SO ₂	642.5	441.7
		VOC	8022.42	6565.1
		CO	3580.7	876.6
		NO _x	873.4	574.3
		HAPs*	391.3	1062.7
Air Contaminates		Ammonia	24.9	63.7
		H ₂ S	83.4	357.1
803	Pre-flash Column Reboiler	PM	0.4	1.3
		PM ₁₀	0.4	1.3
		SO ₂	1.8	6.0
		VOC	0.3	1.0
		CO	2.6	8.7
		NO _x	1.9	6.2
		Ammonia	0.2	0.6
		H ₂ S	0.1	0.1
804	#4 Atmospheric Furnace	PM	2.8	9.2
		PM ₁₀	2.8	9.2
		SO ₂	12.3	41.5
		VOC	2.0	6.7
		CO	14.6	49.2
		NO _x	16.4	55.4
		Ammonia	1.2	3.9
		H ₂ S	0.2	0.4
805	No. 4 Pre-flash Column Reboiler	PM	0.8	2.5
		PM ₁₀	0.8	2.5
		SO ₂	3.3	11.2
		VOC	0.6	1.8
		CO	6.1	20.6
		NO _x	3.5	11.6
		Ammonia	0.4	1.1
		H ₂ S	0.1	0.1
805N	#4 Vacuum Furnace	PM	1.4	4.7

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		PM ₁₀	1.4	4.7
		SO ₂	6.3	21.1
		VOC	1.0	3.4
		CO	7.4	25.0
		NO _x	6.5	21.9
		Ammonia	0.6	2.0
		H ₂ S	0.1	0.2
806	#6 Hydrotreater Furnace/Reboiler	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	1.3	4.4
		VOC	1.0	4.4
		CO	3.2	10.9
		NO _x	5.5	18.4
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1
808	#7 FCCU Furnace	PM	0.6	2.0
		PM ₁₀	0.6	2.0
		SO ₂	2.7	8.9
		VOC	0.5	1.5
		CO	6.5	21.8
		NO _x	2.8	9.3
		Ammonia	0.3	0.9
		H ₂ S	0.1	0.1
809	#7 Catalyst Regenerator Stack	PM	7.5	32.9
		PM ₁₀	7.5	32.9
		SO ₂	13.3	58.3
		VOC	4.2	18.1
		CO	116.0	101.9
		NO _x	7.7	33.5
		Ammonia	0.6	2.5
810	#9 Hydrotreater Furnace/Reboiler	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	3.1	10.3
		VOC	1.0	4.4
		CO	7.5	25.3
		NO _x	12.7	43.0
		Ammonia	0.3	1.0
		H ₂ S	0.1	0.1
811	#9 Reformer Furnace	PM	1.5	5.6
		PM ₁₀	1.5	5.6

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		SO ₂	6.8	25.2
		VOC	1.1	4.4
		CO	16.6	61.6
		NO _x	9.1	33.6
		Ammonia	0.7	2.4
		H ₂ S	0.1	0.3
812	#9 Stabilizer Reboiler	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	1.1	4.4
		VOC	1.0	4.4
		CO	2.7	9.0
		NO _x	4.6	15.4
		Ammonia	0.2	0.4
		H ₂ S	0.1	0.1
813a	#10 Hydrotreater Furnace/Reboiler	PM	0.6	2.0
		PM ₁₀	0.6	2.0
		SO ₂	0.8	3.0
		VOC	0.4	1.4
		CO	2.0	7.2
		NO _x	0.9	3.1
		Ammonia	0.1	0.3
		H ₂ S	0.1	0.1
814	#11 Deasphalting Furnace	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	1.4	4.7
		VOC	1.0	4.4
		CO	3.4	11.6
		NO _x	5.8	19.7
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1
821 (a,b,c total)	Refinery Boilers (fuel gas/natural gas firing)	PM	7.8	31.1
		PM ₁₀	7.8	31.1
		SO ₂	22.4	81.3
		VOC	9.8	39.1
		CO	474.2	123.2
		NO _x	20.0	58.0
		Ammonia	2.1	8.4
		H ₂ S	0.2	0.6
821 (a,b,c)	Refinery Boilers (fuel oil firing)	PM	15.7	
		PM ₁₀	15.7	

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
total)		SO ₂	37.3	
		VOC	20.0	
		CO	474.2	
		NO _x	66.6	
		Ammonia	2.1	
		H ₂ S	0.2	
822	High and Low Pressure Flares	PM	99	4.0
823		PM ₁₀	99	4.0
		SO ₂	484	19.6
		VOC	842	34.1
		CO	2,220	89.9
		NO _x	612	24.8
		Ammonia	0.1	0.1
		H ₂ S	0.1	0.1
828	Asphalt Rack Steam Heater	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.1	4.4
		NO _x	1.8	6.1
		Ammonia	0.1	0.2
		H ₂ S	0.1	0.1
830	Regenerant Furnace	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.0	4.4
		NO _x	1.0	4.4
		Ammonia	0.1	0.1
		H ₂ S	0.1	0.1
831	#9 Continuous Catalyst Regenerator	PM	2.0	8.8
		PM ₁₀	2.0	8.8
		SO ₂	2.0	8.8
		VOC	2.0	8.8
		CO	2.6	11.4
		NO _x	2.0	8.8
832	47 Asphalt Tank Heaters	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	4.3	14.7
		VOC	1.0	4.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		CO	10.6	35.9
		NO _x	12.9	43.6
		Ammonia	0.5	1.4
		H ₂ S	0.1	0.2
841A	G3512TA Air Compressor	PM	0.3	1.1
		PM ₁₀	0.3	1.1
		SO ₂	0.1	0.1
		VOC	1.1	3.6
		CO	7.0	23.7
		NO _x	4.7	15.8
		Ammonia	1.4	5.9
842	#12 Unit Distillate Hydrotreater	PM	1.0	4.4
		PM ₁₀	1.0	4.4
		SO ₂	2.2	7.4
		VOC	1.0	4.4
		CO	5.4	18.1
		NO _x	5.3	17.8
		Ammonia	0.3	0.7
		H ₂ S	0.1	0.1
		PM	12.0	52.7
		PM ₁₀	12.0	52.7
		SO ₂	19.1	53.4
		VOC	1.5	6.6
		CO	8.1	35.6
		NO _x	6.0	26.4
844	Sulfur Recovery Plant Incinerator	Ammonia	0.1	0.1
		H ₂ S	0.6	2.3
846	Gasoline/Diesel Loading Rack	VOC	20.2	17.1
		Ammonia	0.1	0.1
847	Heavy Oil Loading Racks	VOC	647.2	282.9
		Ammonia	4.7	0.9
849	Standby Diesel Crude Pump	PM	1.4	1.4
		PM ₁₀	1.4	1.4
		SO ₂	1.2	1.2
		VOC	1.6	1.5
		CO	12.2	11.6
		NO _x	20.2	19.1
		Ammonia	0.1	0.1
850	Asphalt Hot Oil Heater	PM	1.0	4.4
		PM ₁₀	1.0	4.4

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	2.1	7.2
		NO _x	3.6	12.3
		Ammonia	0.1	0.3
		H ₂ S	0.1	0.1
851a	Wastewater Collection, Treatment, and Storage - new	VOC	26.1	85.9
		Ammonia	0.1	0.1
853	Cooling Towers	PM	15.9	63.3
853a		PM ₁₀	15.9	63.3
853b		VOC	15.3	67.4
859				
854	Fugitive Equipment Leaks	VOC	680.1	2,979.0
		Ammonia	1.0	4.4
		H ₂ S	80.2	351.3
856	Tank Plantwide Bubble	PM	16.4	7.3
		PM ₁₀	16.4	7.3
		VOC	5728.2 ²	2563.5
		CO	123.6	55.3
		Ammonia	3.3	14.2
856A	Tank Plantwide Bubble – Asphalt Tanks	VOC	*	10.0
857	Naphtha Splitter Reboiler Heater	PM	0.8	2.8
		PM ₁₀	0.8	2.8
		SO ₂	2.1	7.9
		VOC	1.0	3.5
		CO	5.2	19.4
		NO _x	2.2	8.2
		Ammonia	0.2	0.8
		H ₂ S	0.1	0.1
858f	Tier 2 Fugitives Annual VOC Bubble	VOC	---	41.3
858t	Tier 2 Tanks Annual VOC Bubble	VOC	---	322.5
860	ULSD Hydrotreater Heater	PM	0.7	2.3
		PM ₁₀	0.7	2.3
		SO ₂	1.7	6.5

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		VOC	0.8	2.9
		CO	4.2	15.8
		NO _x	1.8	6.7
		Ammonia	0.2	0.7
		H ₂ S	0.1	0.1
861	"New" Hydrogen Plant Heater(s)	PM	2.2	7.1
		PM ₁₀	2.2	7.1
		SO ₂	6.1	20.5
		VOC	2.7	9.0
		CO	25.9	50.0
		NO _x	8.1	27.3
		Ammonia	0.6	1.9
		H ₂ S	0.1	0.2
862	Hot Oil Heater	PM	0.4	1.2
		PM ₁₀	0.4	1.2
		SO ₂	1.6	5.3
		VOC	0.3	0.9
		CO	3.8	12.8
		NO _x	3.3	11.0
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1
864	Dredge Engine	PM	0.1	0.2
		PM ₁₀	0.1	0.2
		SO ₂	0.3	1.3
		VOC	0.9	3.8
		CO	0.3	1.4
		NO _x	0.9	3.8
		Ammonia	0.9	3.5
865	Booster Pump Engine	PM	0.1	0.3
		PM ₁₀	0.1	0.3
		SO ₂	0.3	1.1
		VOC	0.8	3.2
		CO	0.2	0.9
		NO _x	0.8	3.2
		Ammonia	0.7	2.9
867	OCC Generator	PM	0.3	0.1
		PM ₁₀	0.3	0.1
		SO ₂	0.3	0.1
		VOC	0.4	0.1
		CO	0.9	0.3

Lion Oil Company
 Permit #: 0868-AOP-R10
 AFIN: 70-00016

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
		NO _x	4.2	1.1
		Ammonia	0.8	0.2
868	IT Generator	PM	0.1	0.1
		PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	0.1
		NO _x	1.6	0.4
		Ammonia	0.1	0.1
869	Tank 536 Truck Loading Rack	Vapor Balanced. Leak emission accounted for in other sources.		
870	Fire Pump Engine	PM	0.3	0.1
		PM ₁₀	0.3	0.1
		SO ₂	0.1	0.1
		VOC	0.6	0.2
		CO	4.6	1.2
		NO _x	8.5	2.2
		HAPs	0.01	0.01
871	Fire Pump Engine	PM	0.3	0.1
		PM ₁₀	0.3	0.1
		SO ₂	0.1	0.1
		VOC	0.6	0.2
		CO	4.6	1.2
		NO _x	8.5	2.2
		HAPs	0.01	0.01
Facility	Facility HAPs	HAPs	391.3	1062.7

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.

SECTION III: PERMIT HISTORY

Permit #82-A was issued on November 19, 1971. This permit was for the construction of a sodium hydrosulfide plant to replace the existing sulfur recovery plant.

Permit #167-A was issued September 28, 1973. This permit approved a catalytic cracking facility by combining two catalytic cracking units into one.

Permit #252-A was issued in July 1974. This permit allowed the replacement of three uncontrolled flares with one John Zink STF-SA-24S smokeless flare.

Permit #167-A (modification) was issued on September 27, 1974. This permit allowed the continued operation of the #3 fluid catalytic cracking unit beyond the period designated in the original permit in order to allow time to increase the capacity of the #7 unit.

Permit #337-A was issued on May 28, 1976. This permit allowed the installation of a stripper to remove H₂S from the refinery wastewater stream with the off gas being treated by the existing sodium hydrosulfide unit.

Permit #338-A was issued on May 28, 1976. This permit allowed the installation of a scrubber-incinerator-waste heat boiler to control emissions from the Asphalt Plant.

Permit #423-A was issued on August 18, 1977. In this permit, the facility proposed to install a baghouse to control asbestos emissions from the protective coatings plant.

Permit #438-A was issued on November 18, 1977. This permit allowed the installation of a pre-flash column reboiler heater in order for the facility to meet the EPA's requirement to reduce lead in gasoline.

Permit #454-A was issued on March 24, 1978. This permit allowed the facility to replace the existing truck loading dock with a new truck transport terminal for gasolines, distillates, and LPGs.

Permit #337-A (modification) was issued in March 1978. There had been a delay in the modification of the hydrosulfide unit. This permit allowed the facility to operate the stripper prior to the upgrade.

Permit #520-A was issued on September 29, 1978. This permit allowed the installation of new and revamped platforming and unifining furnaces in order for the facility to meet the second part of the lead phasedown as required by the EPA.

Permit #252-A (modification) was issued in June, 1979. This permit allowed the replacement of two 16 inch flares with one 24 inch high pressure flare.

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

Permit #252-A (modification) was issued on November 20, 1981. This permit allowed the facility to replace a gasoline blending storage tank that had been condemned by increasing the use of the remaining tanks and reactivating out of service tanks. In order to comply with NSPS requirements Tank #124 was fitted with a secondary seal to the external floating roof. Tanks #108 and #109 were fitted with internal floating roofs.

868-A

Permit #868-A was issued on January 4, 1988. This permit served to consolidate all of the active permits held by this facility into one permit. It also permitted an asphalt loading heater and Isomerization Project as part of the lead phasedown required by the EPA.

868-AR-1

Permit #868-AR-1 was issued on December 26, 1990. This modification allowed the installation of a topping furnace on the #4 crude unit.

868-AR-2

Permit #868-AR-2 was issued on June 7, 1991. This modification allowed the installation of a continuous catalyst regeneration unit of a platforming unit.

868-AR-3

Permit #868-AR-3 was issued on January 5, 1993. This modification permitted the installation of a 100,000 barrel asphalt storage tank.

868-AR-4

Permit #868-AR-4 was issued on May 27, 1993. This modification permitted the installation of a distillate hydrotreater with a capacity of 20,000 barrels per day. The purpose of this modification was to make on-road diesel quality fuel to meet the Clean Air Act Standards.

1596-A

Permit #1596-A was issued on January 31, 1995. This permit allowed the installation of a Sulfur Recovery Plant to produce elemental sulfur.

868-AR-5

Permit #868-AR-5 was issued on August 12, 1996. This modification dealt with the installation of a new 50,000 barrel storage tank to replace an existing tank, installation of a 25,000 BPD vacuum furnace to replace an existing furnace, installation of a Sulfur Recovery Plant to replace the existing Sodium Hydrosulfide Unit, and documented the emissions from on-site storage

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

tanks, product loading racks, and process fugitive emissions. Permits #868-AR-4 and #1596-A were consolidated.

868-AR-6

Permit #868-AR-6 was issued on February 6, 1998. This minor modification was to install a standby diesel fueled crude pump in order for Tank #63 (SN T-63 for this permit, SN-73 of the old permit) to meet the standards of 40 C.F.R. § 63, Subpart CC- *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. The installation of the new pumping system allowed the tank to be taken out of crude oil storage service, and to be classified as a Group II storage vessel. This minor modification also allowed the facility to reduce VOC emissions from the tank, reduce crude oil inventories, and provide full emergency standby crude capacity in the event of a power failure.

868-AR-7

Permit #868-AR-7 was issued on June 3, 1998. The purpose of this minor modification was to install an above ground storage tank (SN T-552) to replace an underground storage tank used to store gasoline for the company's motor fuel demands. The underground tank was owned by a company which provided fuel to Lion Oil.

868-AOP-R0

Permit #868-AOP-R0 was issued on December 12, 2000 as the first operating permit for this facility as per the requirements of Regulation #26 and 40 C.F.R. § 70. In this permit, all of the tanks at the facility were bubbled under a PAL such that the facility has to comply with one VOC limit for the tank farm instead of a limit for each tank. Under this permit, the facility has permitted several sources that were previously unpermitted and increased several throughputs. The following minor modification and de minimis changes that were previously allowed were also included.

Minor modification submitted in September 1998: Permitted the Polymer Asphalt Let-Down Facility. The project consisted of installing a new gas fired hot oil system (SN-850), installation of two new tanks (SN's T-553 and T-554), modification of tanks (SN's T-24, T-384 through T-387)

De minimis change submitted May 1999: Allowed the facility to replace the existing Sour Water Stripper with a new 400 gal/min Sour Water Stripper to minimize odors at the refinery. A new 20,000 barrel storage tank for the storage of sour water was also installed as part of the project.

De minimis change submitted October 1999: Allowed the facility to upgrade the #4 Crude Unit with new and refurbished equipment. The improvements included the installation of seven pumps and approximately 236 hydrocarbon valves with associated flanging and the removal of two pumps, 198 hydrocarbon valves and associated flanging. The improvements to the #4 Crude Unit also allowed the facility to produce intermediates that were previously purchased from

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

outside sources. Associated equipment that will be affected by the changes at the facility are the #4 Pre-flash Column Reboiler (SN-03), #4 Atmospheric Furnace (SN-04), the #4 Vacuum Furnace (SN-05), the #11 Deasphalting Furnace (SN-14), the Asphalt Loading Racks (SN's 205-208), Asphalt Storage Tanks #39, #40, #41, #55, #84, #219, and #368, and Diesel Storage Tanks #121 and #122.

De minimis change submitted February 1999: Allowed the facility to construct a new 5,000 barrel asphalt storage tank (SN T-78) to replace the existing 2,500 barrel storage tank. In previous permitting actions, the tank numbers did not coincide with the source numbers. In order to eliminate confusion and correct the problem, the source numbers for the facility were changed in this permitting action. Source numbers 01-700 are reserved for tank purposes. Source numbers for the other sources start at 801.

868-AOP-R1

Permit No. 868-AOP-R1 was issued to Lion Oil Co. on Dec. 5, 2003. This permit was the first modification to Permit #868-AOP-R0. It was issued as a part of the Permit Appeal Resolution between the Department and the facility. The following changes were made in this permit:

- a. The method of demonstrating compliance with the emission limits for the facility's tanks was changed to allow the facility to track refinery crude feed rate instead of conducting a monthly emissions inventory.
- b. A plantwide applicability limit was established for various other air pollutants in lieu of individual source emission limits.
- c. The effective dates of several of the testing conditions and opacity readings were modified or changed.
- d. Several equipment capacities were corrected or modified.
- e. The Plantwide Conditions were modified to clarify the difference between refinery fuel gas and desulfurized refinery fuel gas and which sources were able to burn which fuels.
- f. Clarifications were made regarding applicability of various regulations. Various wording changes and typographical and error corrections were made throughout the Permit.
- g. Various alternate operating scenarios were added to allow the facility flexibility in its operations. The frequency of monitoring the Btu content of the NSPS J quality gas was clarified. The Cooling Towers section (SN-853) was changed to include two cooling towers that were omitted from the previous permit. The emissions were updated to include particulate emissions.
- h. The Insignificant Activities List was updated.
- i. The Permit was updated to reflect the installation of a flare gas recovery system to recover refinery gases. The Permit was updated to reflect the installation of two additional 5,000 barrel storage tanks (T-382 and T-383) and one additional

loading rack (PMA #2 Loading Rack).

- j. Two new gas oil tanks, one 2,000 bbl storage tank (T-19), and one 8,200 bbl storage tank (T-59) were added to the permit. These tanks were constructed to replace two older existing tanks (T-20 and T-21) which were removed from service. These two new tanks were incorporated into the facility-wide PAL for VOC emissions from tanks.
- k. One additional gas fired tank heater was permitted for installation in asphalt storage tank No. 78 (T-78). This new heater is rated at 0.68 MMBtu/hr.
- l. The installation of a new, enclosed process wastewater treatment system was permitted with this modification. This new system allows for the segregation of process wastewater from refinery stormwater. The existing wastewater treatment system will be converted to stormwater-only usage once the new system is completed. This change should result in significant decreases in VOC emissions from the wastewater treatment systems at the refinery.

868-AOP-R2

Permit No. 868-AOP-R2 was issued to Lion Oil Co. on January 3, 2005. With this modification, the facility modified, or will be modifying several units, and installing new equipment in order to produce low-sulfur diesel fuel and gasoline to meet the new US EPA "Tier II" fuel sulfur requirements. The changes which occurred at the plant which are associated with the Tier II project are as follows:

- a. A new naphtha splitter was installed in the refining process following the #7 Fluid Catalytic Cracking Unit (FCCU).
- b. The existing #10 Diesel Hydrotreater was converted to treat FCC heavy naphtha.
- c. The #12 Unit Distillate Hydrotreater Stripper Reboiler Furnace (SN-843) was retrofitted with new piping to allow it to serve as the #10 unit Stripper Reboiler Furnace. After further evaluation, this heater will remain in its present service. There was no emissions change with this modification.
- d. New non-fired heat exchangers were installed in the #12 Unit to supply heat previously supplied by the #12 Distillate Hydrotreater Stripper Reboiler Furnace.
- e. A new diesel hydrotreater was installed (No. 8 ULSD Hydrotreater) to replace the #10 Diesel Hydrotreater and to produce Ultra-Low Sulfur Diesel (ULSD).
- f. A wet gas scrubber (WGS) was installed on the #7 FCCU Catalyst Regenerator Stack (SN-809) in order to reduce emissions of sulfur dioxide (SO₂) and particulate matter (PM/PM₁₀).
- g. New equipment and piping was installed to handle wastewater from the No. 8 Unit and the WGS and to comply with NSPS QQQ where applicable.
- h. The catalyst utilized in the #9 CCR (SN-831) was changed to improve hydrogen production.

- i. The sulfur recovery capacity of the Sulfur Recovery Plant (SN-844) was increased to handle the increased sulfur removed from the fuel oil and gasoline.
- j. Three existing tanks (T-113, T-247, and T-372) were converted from diesel to FCC gasoline and heavy naphtha service. SN-113 was retrofitted with an external floating roof, and SN-247 and SN-372 were retrofitted with internal floating roofs.
- k. The diesel throughput of the following tanks increased: T-54, T-108, T-109, T-119, T-121, and T-122. No other changes have occurred at any of these tanks.
- l. Two new process heaters were installed. One at the #7 FCC Naphtha Splitter Reboiler, and one at the No. 8 ULSD Hydrotreater. These two heaters have been permitted as SN-857 and SN-860.
- m. A new emission bubble was added to the permit to simplify tracking of emissions associated with the Tier II clean fuels project. This bubble includes all emissions from fugitive sources associated with the Tier II project, as well as emissions from the tanks which were either modified, or experienced a throughput increase associated with the project. This source has been assigned SN-858. The tanks associated with the Tier II project were previously included in the refinery tanks bubble (SN-856). Permitted VOC emissions from SN-856 were decreased by the amount of the most recent available data for past actual emissions from the Tier II tanks.
- n. The No. 1 Cooling Tower was replaced with the new No. 8 Cooling Tower (SN-859). This change was necessary to provide for the increased process cooling water demands due to the new equipment associated with the Tier II changes. Although the No. 8 Cooling Tower has a higher cooling water handling capacity, permitted emissions will decrease with this change due to the use of drift eliminators for emissions control in the No. 8 tower.

Additionally, the following changes were made to the permit. These changes are not specifically associated with the tier II project, but were included in the permit at this time.

- a. Lion Oil proposed to lower permitted CO emissions from the No. 7 FCCU Catalyst Regenerator Stack (SN-809) to comply with provisions of the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. CO emissions from this source were required to comply with limits of 500 ppmvd at 0% O₂ (1-hour average) and 100 ppmvd at 0% O₂ (365-day rolling average). This resulted in a very substantial decrease in permitted CO emissions from this source (10,463.1 tpy decrease).
- b. A new non-contact condenser was installed on the Vacuum Distillation Unit (VDU). This change virtually eliminated VOC emissions from the VDU. These VOC emissions were previously routed through the No. 1 cooling tower, and included in SN-852. This changes resulted in a decrease in permitted VOC emissions of 242.1 tpy. Small quantities of VOC may continue to be emitted from the VDU in the form of fugitive equipment leaks. Such emissions are covered by SN-858, the Tier II fugitives and tanks emissions bubble.

- c. Catalytic converters and air/fuel ratio controllers were installed on the North 8 and South 10 SVG compressors (SN-837 and SN-838) and the East and West JVG compressors (SN-839 and SN-840). These controls were installed as a “supplemental environmental project” pursuant to paragraph 32(A) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. These controls were not installed pursuant to “BACT” or any portion of the NSR or PSD programs. The installation of these controls reduced emissions of NO_x and CO from these four compressor engines.
- d. A catalytic converter and air/fuel ratio controller was installed on the air compressor (SN-841) pursuant to BACT requirements and paragraph 16(B)(ii) of the Consent Decree (CIV. No. 03-1028). The installation of these controls reduced emissions of NO_x and CO from this compressor engine.
- e. A continuous emissions monitor (CEM) system was be installed on the #4 Atmospheric Furnace (SN-804). This system was installed in order to demonstrate compliance with an emission limit of 0.045 lb NO_x/MMBtu which was established pursuant to the Consent Decree (CIV. No. 03-1028) between Lion Oil Co., the US EPA, and ADEQ.
- f. Several new requirements were added to the permit to clarify regulatory applicability and other administrative issues as required by the Consent Decree (CIV. No. 03-1028) between Lion Oil, the US EPA, and ADEQ. No emissions changes resulted from these new permit conditions.
- g. As a result of the Consent Decree (CIV. No. 03-1028), three of the existing boilers (SN-818, 819, 820) were now identified as subject to the provisions of 40 C.F.R. § 60 Subpart J. Compliance with the NSPS requirements for H₂S concentration in the fuel gas resulted in a decrease in SO₂ emissions from these sources.

As a result of all of the modifications performed at the plant with this permit revision, overall permitted annual emissions limitations for the facility changed as follows: PM₁₀ decreased by 273.0 tpy, SO₂ decreased by 2,338.8 tpy, VOC decreased by 299.7 tpy, CO decreased by 10,620.0 tpy, and NO_x decreased by 89.2 tpy. There were no changes to any limits contained in the existing non-criteria pollutants bubble limits contained in this permit. The facility was required to continue to demonstrate compliance with these limits.

868-AOP-R3

Permit No. 868-AOP-R3 was issued to Lion Oil Co. on November 28, 2006. This permit action serves to complete the renewal requirement of Regulation 26 and 40 C.F.R. §70. This action also incorporated several modifications and minor modifications to the Title V Operating Air Permit for this facility. These modifications include the following changes.

- The replacement of the five existing refinery boilers (SN-816 through SN-820) with three new boilers (SN-821a, b, c);
- The incorporation of the requirements of 40 C.F.R. Pat 60, Subparts Db and J and

40 C.F.R. § 63, Subpart DDDDD as they apply to the new boilers;

- The incorporation of the requirements of 40 C.F.R. § 63, Subpart UUU as they apply to the Fluid Catalytic Cracking Unit (FCCU) and the Sulfur Recovery Unit (SRU), and the Catalytic Cracking Unit (CCR).
- The removal of SN-843, the #12 Stripper Reboiler Heater;
- The installation of drift eliminators in the #5 Cooling Tower (SN-853a);
- The installation of a new 150,000 bbl asphalt storage tank (T-112) to be incorporated into the existing tank plantwide applicability limit (SN-856). This tank will be heated by a hot oil heater system (SN-862). This heater will be added to the existing tank heater bubble (SN-832);
- The replacement of the #10 Furnace/Reboiler (40 MMBtu/hr, SN-813) with a new process heater (17.9 MMBtu/hr, to be designated as SN-813a);
- An increase in the allowable cooling water flow rate through the #8 Cooling Tower (SN- 859). There is no increase in the permitted emissions from the cooling tower with this change because past emissions were significantly over-estimated for this source.
- The replacement of 3,341 bbl asphalt storage tank with a new tank of equal dimensions. Emissions are not affected; 40 C.F.R. § 60, Subpart UU is triggered for the new tank; and,
- Increased annual emissions and annual heat input capacity permitted at the #9 Reformer Furnace (SN-811). Installation of a new Hydrogen Plant Heater (SN-861). These changes are an extension of the previously permitted and approved Tier II Fuels Project. The total project still meets minor modification applicability.

The primary change associated with this modification was the boiler replacement project. This project is required under the terms of the Consent Decree (CIV. No. 03-1028) reached by Lion Oil, ADEQ, and the US EPA. Under the terms of this agreement the new boilers must be in operation by January 1, 2007, and the five old boilers must be permanently shutdown prior to this date. The old boilers remain permitted for operation until December 31, 2006.

Other changes result from the renewal application. Various emission rates have been re-evaluated using updated emission factors for renewal purposes. Most changes are trivial, however; changes to the tanks PAL (SN-856) and fugitive PAL (SN-854) cause for a decrease in VOC emissions by several thousand tons per year. As a result of all the modifications and renewal updates, facility-wide permitted emission limitations have changed as follows: PM 0 tpy; PM₁₀ -295.6 tpy; SO₂ 1.6 tpy; VOC -5,138.7 tpy; CO 61.9 tpy; NO_x -7.7 tpy.

868-AOP-R4

Permit No. 868-AOP-R4 was issued to Lion Oil Co. on March 7, 2007. This permit revision incorporated the following changes:

- Routed the #7 FCCU Catalyst Hopper Vents, SN-848, to the wet gas scrubber of the #7 FCCU unit (SN-809).
- Increased short-term NO_x emission limits in lb/MMBtu on a 3-hour average basis based upon actual performance as demonstrated by a CEMS and performance tests.
- Increased the permitted annual emissions and annual heat input capacity of the Hydrogen Plant Heaters (SN-861) by installing two new, replacement units.
- Increased the permitted emissions at the Tier II Heaters, Naphtha Splitter Reboiler Heater (SN-857) and ULSD Hydrotreater Heater (SN-860), by 0.3 tpy VOC , each respectively, and 0.1 tpy CO at SN-857.
- Decreased the permitted particulate emissions at the Tier II Heaters, SN-857 and SN-860, by -1.6 and -1.3 tpy, respectively.
- Installed a 150,000 bbl storage vessel for additional asphalt storage.
- Removed T-56, T-57, T-60, T-81, and T-83 from the list of permitted tanks.

868-AOP-R5

Permit No. 868-AOP-R5 was issued to Lion Oil Co. on October 1, 2007. This permit revision incorporated the following changes:

- Redesign of the CDU featuring a new No. 4 Vacuum Furnace (SN-805N).
- Retrofit SN-803 and SN-805 with new, next generation ultra-low NO_x burners.
- Increase the heat input capacity for SN-804.
- Increase the capacity at the FCCU (SN-809) from approximately 19,700 BPD to over 25,000 BPD.
- Install new, No. 9 Cooling Tower, SN-853-9.
- Increase the gallons per minute flow rate through the No. 5 Cooling Tower.
- Install a new crude oil storage tank (T-998).
- Replace G398TA Air Compressor (SN-841) with G3512TA (SN-841A).

868-AOP-R6

Permit 868-AOP-R6 was issued on September 16, 2008. This permit revision incorporates the following changes:

The pump upgrades and additional loading arms will allow the loading of products that were previously loaded at the 56 rack, which will then be discontinued upon completion of the project. Total emission increases at SN-847 due to these rack modifications are 19.6 tpy VOC. Annual

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

throughput from asphalt loading at the PMA Truck racks and the 111/219 West Racks shall be limited to no more than 4.44 MM bbl and 1.92 MM bbl.

The facility has determined that it will not be necessary to construct the No. 9 Cooling Tower as part of the Refinery Expansion project and has thus adjusted the particulate and VOC netting analysis accordingly. Also, the facility is taking credit for a controlled emission factor for VOC at the No. 5 Cooling Tower increase.

Tank T-42 has not been included in any application submittal since the original Title V Air Permit. The tank is approximately 31,600 gallons and is not subject to any NESHAP or NSPS requirements. It was constructed in 2007. Emissions from this source are 39.6 tpy VOC.

Cutback asphalt has been eliminated at the facility. Tank emissions that have been affected are T-170, T-199, T-180, T-190, T-310, T-311, T-312, T-313, T-314, T-315, T-319, T-320, T-321, T-322, T-323, T-325, T-326, T-327, T-328, T-331, T-332, T-333, T-335, T-336, T-337, T-338, T-340, T-349, T-350, T-324, T-351, T-72, T-353, T-145, T-339, T-73, T-352, T-74, T-201, T-162, T-173. Emissions of VOC have been reduced by 82.0 tpy from these tanks. The Asphalt Plant south Truck Rack and the Pumphouse Truck Rack have taken a limit of 10.3 tpy, SN-847a, to take a credible decrease for elimination of cutback asphalt.

The following tanks in SN-858 have been removed from the permit: T-012, T-015, T-016, T-017, T-018, T-021, T-025, T-027, T-031, T-043, T-044, T-045, T-046, T-047, T-048, T-049, T-055, T-056, T-057, T-060, T-075, T-077, T-081, T-083, T-116, T-117, T-129, T-133, T-134, T-158, T-159, T-160, T-161, T-163, T-164, T-165, T-166, T-200, T-226, T-228, T-305, T-411, T-412, T-520, T-550, and T-604. Emission reductions from this change are 199.4 tpy VOC.

- Add a new DS-028 Naphtha Loading/Unloading Rack

The facility experienced a refinery upset which resulted in damage to the No. 9 Reformer Furnace, and as a result, will be running at less than full capacity until repairs are made. In order to maintain balance at the facility, Lion must offload naphtha feed, which is normally processed in the No. 9 Reformer, to trucks until the repairs are completed. Emission estimates are 7.0 tpy (after rounding) VOC, based upon a maximum of 56,000 bbl over the repair period.

Total permitted emission changes from all changes are a reduction of VOC and CO by 497.7 tpy and 4.3 tpy respectively.

Due to these changes, the Refinery expansion project netting analysis, part of Air Permit 868-AOP-R5, was revisited in order to determine if the associated emission increases exceeded the definition of a "significant net increase" as defined by the Federal Prevention of Significant Deterioration (PSD) regulations. This analysis demonstrated that there was little change to the significant net emission increases for VOC and PM₁₀.

868-AOP-R7

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

This permit was issued on August 10, 2009. Lion Oil replaced the #7 Cooling Tower. The cooling tower was previously included with source SN-853 which included a number of towers. The #7 Cooling Tower is now designated as SN-853b. Permitted emissions for the facility did not change. The #7 Cooling Tower was given a separate water throughput limit to insure its emissions cannot exceed the PSD thresholds.

868-AOP-R8

Permit 868-AOP-R8 was issued on February 3, 2011. This permit modification incorporated three minor modifications. The first minor modifications allowed for Lion Oil to store and blend ethanol with its gasoline and changes service of three storage tanks. Tank 103 was converted to naphtha service, Tank 126 is now premium gasoline service and Tank 532 will store ethanol. The changes in tank service did not effect the permit language as all the tanks are allowed to store materials with a vapor pressure less than 11.1 psi.

Lion Oil also added a 140 hp (SN-864) dredge engine and a 112 hp (SN-865) booster pump. Both engines are diesel-fired engines and will be used as part of the Corrective Action Management Unit facility being built in order to effectively treat sludge accumulations in the Solid Waste Management units that are targeted for remediation.

Lion added a splitter column to meet the requirements of the Mobile Source Air Toxics Phase II regulation. The splitter column permitted emissions are due only to the equipment leaks and have been added to Fugitive Equipment Leaks (SN-854).

In addition to the above minor modifications Lion Oil is required by its Consent Decree (CIV.; No. 03-1028) to incorporate into its permit NO_x emission limits for the FCCU (SN-809) and certain heaters, boilers, and compressors. In this permit, limits for SN-808, SN-809, SN-810, SN-811, and SN-842 were updated and monitoring conditions were added to monitor NO_x emissions for SN-803, SN-805, SN-808, SN-809, SN-810, SN-811, and SN-842.

868-AOP-R9

This permit was issued on September 8, 2011. With this modification, Lion Oil established a BACT limit for filterable and condensable particulate emission from the Fluid Catalytic Cracking Unit (FCCU), SN-809. The establishment of the condensable limit was a permit requirement to be done by Lion Oil after modification of the source and testing was complete. The limit of 1.0 lb condensable PM₁₀/1000 coke burn-off was based off that testing. Lion Oil also raised a limit for the Reformer Furnace, SN-811 from 0.035 lb/MMBTU to 0.045 lb/MMBTU. The previous lower limit for this source was based on testing during winter months. Due to different conditions in summer and the complex air to fuel ratio issues caused by having combustion air inlets into the source, the limit was raised by 0.01 to allow for some flexibility while still showing proper operation of the source.

SECTION IV: SPECIFIC CONDITIONS

Furnaces, Heaters, and Reboilers

SN-803, 804, 095, 805N, 806, 808, 810, 811, 812, 813a, 814, 828, 830, 842, 850, 857, 860, 861, 862,

**SN-803 - #4 Pre-flash Column Reboiler
SN-804 - #4 Atmospheric Furnace
SN-805 - No. 4 Pre-flash Reboiler
SN-805N - #4 Vacuum Furnace
SN-806 - #6 Hydrotreater Furnace/Reboiler
SN - 808-#7 FCCU Furnace
SN-810 - #9 Hydrotreater Furnace/Reboiler
SN-811 - #9 Reformer Furnace
SN-812 - #9 Stabilizer Reboiler
SN-813a - #10 Hydrotreater Furnace/Reboiler
SN-814 - #11 Deasphalting Furnace
SN-828 - Asphalt Rack Steam Heater
SN-830 - Regenerant Furnace
SN-842 - #12 Unit Distillate Hydrotreater
SN-850 - Asphalt Hot Oil Heater
SN-857 - Naphtha Splitter Reboiler
SN-860 - ULSD Hydrotreater Heater
SN-861 - Hydrogen Plant Heater
SN-862 - Hot Oil Heater**

Source Descriptions

All sources in this grouping are subject to 40 C.F.R., Part 60, Subpart J-*Standards of Performance for Petroleum Refineries*.

SN-850 and SN-862 are subject to 40 C.F.R. § 60, Subpart Dc-*Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units*.

SN-803 is a 40 MMBtu/hr reboiler (nominal design) used to maintain the temperature in the pre-flash column in order to separate crude oil into gasoline and naphtha. The reboiler is fueled by NSPS Subpart J quality gas. It was installed in 1979 and will be retrofitted with next generation, ultra-low NO_x burners. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀. BACT for this source is good combustion practice.

SN-804 is a 280 MMBTU/hr source used to heat the bottoms from the pre-flash column in order to separate them into naphtha, kerosene, diesel, and gas oil. The furnace is fueled by NSPS Subpart J quality gas. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀, NO_x, and CO. BACT for this source is good combustion practice and next generation ultra-low NO_x burners.

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

SN-805 is a 75 MM Btu/hr reboiler (nominal design). It was installed in 1996 and will be retrofitted with next generation, ultra-low NO_x burners. On May 17, 2000, this source was tested for NO_x emissions using EPA Reference Method 7E pursuant to §19.702 of Regulation 19, and 40 C.F.R., Part 52, Subpart E. The test results submitted to the Department demonstrated compliance. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀. BACT for this source is good combustion practice.

SN-805N is a 142.2 MMBTU/hr (annual) source. The furnace will be fueled by NSPS Subpart J quality gas. As a result of the refinery expansion permit revision, this source has undergone PSD review for PM₁₀, NO_x, and CO. BACT for this source is good combustion practice and next generation ultra low NO_x burners.

SN-806 is a 20 MMBtu/hr furnace (nominal design) used to raise the temperature of light straight run (LSR) to reaction. It is fueled with NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-808 is a 56 MMBtu/hr furnace (nominal design) used to heat gas oil. It is fueled by NSPS Subpart J quality gas. It was installed in 1979.

SN-810 is a 70 MMBtu/hr furnace (nominal design) used to heat naphtha. It is fueled NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-811 is a 170 MMBtu/hr furnace (nominal design) used to heat the #9 Unit Stripper bottoms. It is fueled by NSPS Subpart J quality gas. It was installed in 1980.

SN-812 is a 25 MMBtu/hr furnace/reboiler (nominal design) used to heat platformate in order to remove low molecular weight gases. It is fueled by NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-813a is a 17.9 MMBtu/hr furnace (nominal design) used to heat light cycle oil, diesel, kerosene, and gas oil. It is fueled by NSPS Subpart J quality gas. It was installed in 2005. This source utilizes ultra-low-NO_x burners for NO_x emissions control.

SN-814 is a 32 MMBtu/hr furnace (nominal design) used to heat asphalt from the bottom of the extraction tower. It is fueled by NSPS Subpart J quality gas. It was installed in 1958. This source was declared subject to NSPS Subpart J as a result of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA.

SN-828 is a 10 MMBtu/hr boiler (nominal design) used to heat asphalt products during truck loading. It is fueled by NSPS Subpart J quality gas. It was installed in 1987.

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

SN-830 is a 1.8 MMBtu/hr furnace (nominal design). It is fueled by NSPS Subpart J quality gas. It was installed in 1987.

SN-842 is a 50.0 MMBtu/hr furnace (nominal design). It is fueled by NSPS Subpart J quality gas. It was installed in 1993.

SN-850 is a 20.0 MMBtu/hr heater (nominal design) used to supply heat to the hot oil system which maintains the elevated temperatures of stored asphalt products so that the material will flow without solidifying. This source was installed in 1998. It is fueled by NSPS Subpart J quality gas. This source is subject to 40 C.F.R. § 60, Subpart Dc-*Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units*.

SN-857 is rated at 53.4 MMBtu/hr. It is fueled by NSPS Subpart J quality gas.

SN-860 is rated at 43.6 MMBtu/hr. It is fueled by NSPS Subpart J quality gas.

At the completion of the Hydrogen Plant Project, this unit will be replaced with two, new units, SN-861, with a combined rating of 138.0 MMBtu/hr. Both are fueled by NSPS Subpart J quality gas.

SN-862 is a 35.2 MMBtu/hr fuel gas-fired hot oil heater (nominal design) and associated hot oil system for temperature control of asphalt tank T-112.

Specific Conditions

FHR 1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for the following sources shall be demonstrated by compliance with Subpart J and the fuel and Btu limits or with other available emissions data for these sources. The pound per hour limits in the following table are on a 3-hour average basis. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Source Description	Pollutant	lb/hr	tpy
803	Pre-flash Column Reboiler	PM ₁₀	0.4	1.3
		SO ₂	1.8	6.0
		VOC	0.3	1.0
		CO	2.6	8.7
		NO _x	1.9	6.2
804	#4 Atmospheric Furnace	PM ₁₀	2.8	9.2
		SO ₂	12.3	41.5
		VOC	2.0	6.7
		CO	14.6	49.2
		NO _x	16.4	55.4

SN	Source Description	Pollutant	lb/hr	tpy
805	No. 4 Pre-flash Reboiler	PM ₁₀	0.8	2.5
		SO ₂	3.3	11.2
		VOC	0.6	1.8
		CO	6.1	20.6
		NO _x	3.5	11.6
805N	#4 Vacuum Furnace	PM ₁₀	1.4	4.7
		SO ₂	6.3	21.1
		VOC	1.0	3.4
		CO	7.4	25.0
		NO _x	6.5	21.9
806	#6 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4
		SO ₂	1.3	4.4
		VOC	1.0	4.4
		CO	3.2	10.9
		NO _x	5.5	18.4
808	#7 FCCU Furnace	PM ₁₀	0.6	2.0
		SO ₂	2.7	8.9
		VOC	0.5	1.5
		CO	6.5	21.8
		NO _x	2.8	9.3
810	#9 Hydrotreater Furnace/Reboiler	PM ₁₀	1.0	4.4
		SO ₂	3.1	10.3
		VOC	1.0	4.4
		CO	7.5	25.3
		NO _x	12.7	43.0
811	#9 Reformer Furnace	PM ₁₀	1.5	5.6
		SO ₂	6.8	25.2
		VOC	1.1	4.4
		CO	16.6	61.6
		NO _x	9.1	33.6
812	#9 Stabilizer Reboiler	PM ₁₀	1.0	4.4
		SO ₂	1.1	4.4
		VOC	1.0	4.4
		CO	2.7	9.0
		NO _x	4.6	15.4
813a	#10 Hydrotreater Furnace/Reboiler	PM ₁₀	0.6	2.0
		SO ₂	0.8	3.0
		VOC	0.4	1.4
		CO	2.0	7.2
		NO _x	0.9	3.1

Lion Oil Company
 Permit #: 0868-AOP-R10
 AFIN: 70-00016

SN	Source Description	Pollutant	lb/hr	tpy
814	#11 Deasphalting Furnace	PM ₁₀	1.0	4.4
		SO ₂	1.4	4.7
		VOC	1.0	4.4
		CO	3.4	11.6
		NO _x	5.8	19.7
828	Asphalt Rack Steam Heater	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.1	4.4
		NO _x	1.8	6.1
830	Regenerant Furnace	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	1.0	4.4
		NO _x	1.0	4.4
842	#12 Distillate Hydrotreater Furnace	PM ₁₀	1.0	4.4
		SO ₂	2.2	7.4
		VOC	1.0	4.4
		CO	5.4	18.1
		NO _x	5.3	17.8
850	Asphalt Hot Oil Heater	PM ₁₀	1.0	4.4
		SO ₂	1.0	4.4
		VOC	1.0	4.4
		CO	2.1	7.2
		NO _x	3.6	12.3
857	Naphtha Splitter Reboiler	PM ₁₀	0.8	2.8
		SO ₂	2.1	7.9
		VOC	1.0	3.5
		CO	5.2	19.4
		NO _x	2.2	8.2
860	ULSD Hydrotreater Heater	PM ₁₀	0.7	2.3
		SO ₂	1.7	6.5
		VOC	0.8	2.9
		CO	4.2	15.8
		NO _x	1.8	6.7
861	Hydrogen Plant Heater(s)	PM ₁₀	2.2	7.1
		SO ₂	6.1	20.5
		VOC	2.7	9.0
		CO	25.9	50.0
		NO _x	8.1	27.3

SN	Source Description	Pollutant	lb/hr	tpy
862	Hot Oil Heater	PM ₁₀	0.4	1.2
		SO ₂	1.6	5.3
		VOC	0.3	0.9
		CO	3.8	12.8
		NO _x	3.3	11.0

FHR 2. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for the following sources shall be demonstrated by compliance with Subpart J and the fuel and Btu limits or with other available emissions data for these sources. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Source Description	Pollutant	lb/hr	tpy
803	Pre-flash Column Reboiler	PM	0.4	1.3
		Ammonia	0.2	0.6
		H ₂ S	0.1	0.1
804	#4 Atmospheric Furnace	PM	2.8	9.2
		Ammonia	1.2	3.9
		H ₂ S	0.2	0.4
805	No. 4 Pre-flash Reboiler	PM	0.8	2.5
		Ammonia	0.4	1.1
		H ₂ S	0.1	0.1
805N	#4 Vacuum Furnace	PM	1.4	4.7
		Ammonia	0.6	2.0
		H ₂ S	0.1	0.2
806	#6 Hydrotreater Furnace/Reboiler	PM	1.0	4.4
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1
808	#7 FCCU Furnace	PM	0.6	2.0
		Ammonia	0.3	0.9
		H ₂ S	0.1	0.1
810	#9 Hydrotreater Furnace/Reboiler	PM	1.0	4.4
		Ammonia	0.3	1.0
		H ₂ S	0.1	0.1
811	#9 Reformer Furnace	PM	1.5	5.6
		Ammonia	0.7	2.4
		H ₂ S	0.1	0.3
812	#9 Stabilizer Reboiler	PM	1.0	4.4
		Ammonia	0.2	0.4
		H ₂ S	0.1	0.1
813a	#10 Hydrotreater Furnace/Reboiler	PM	0.6	2.0
		Ammonia	0.1	0.3
		H ₂ S	0.1	0.1

SN	Source Description	Pollutant	lb/hr	tpy
814	#11 Deasphalting Furnace	PM	1.0	4.4
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1
828	Asphalt Rack Steam Heater	PM	1.0	4.4
		Ammonia	0.1	0.2
		H ₂ S	0.1	0.1
830	Regenerant Furnace	PM	1.0	4.4
		Ammonia	0.1	0.1
		H ₂ S	0.1	0.1
842	#12 Distillate Hydrotreater Furnace	PM	1.0	4.4
		Ammonia	0.3	0.7
		H ₂ S	0.1	0.1
850	Asphalt Hot Oil Heater	PM	1.0	4.4
		Ammonia	0.1	0.3
		H ₂ S	0.1	0.1
857	Naphtha Splitter Reboiler	PM	0.8	2.8
		Ammonia	0.2	0.8
		H ₂ S	0.1	0.1
860	ULSD Hydrotreater Heater	PM	0.7	2.3
		Ammonia	0.2	0.7
		H ₂ S	0.1	0.1
861	Hydrogen Plant Heater(s)	PM	2.2	7.1
		Ammonia	0.6	1.9
		H ₂ S	0.1	0.2
862	Hot Oil Heater	PM	0.4	1.2
		Ammonia	0.2	0.5
		H ₂ S	0.1	0.1

FHR 3. The facility shall not exceed the annual BTU limits for the sources set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Specific Condition #FHR 4. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

SN	Annual Limit (MMBTU/12 months)
803	351,360
804	2,459,520
805	658,800
805N	1,249,085
806	263,520

SN	Annual Limit (MMBTU/12 months)
808	528,006
810	614,880
811	1,493,280
812	219,600
813a	173,045
814	281,088
830	15,811
842	439,200
850	175,680
857	469,066
860	382,982
861	1,212,192

FHR 4. Records of BTUs shall be maintained on a twelve-month rolling basis for the sources listed in Specific Condition #FHR 2. These records shall be updated monthly. These records shall include the fuel combusted (natural gas or NSPS J quality gas) and heat duty (amount of gas x heating value). The permittee shall analyze the BTU content of the fuel gas on a monthly basis. The records of BTU usages shall be maintained on site and submitted in accordance with General Provision #7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

FHR 5. The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline natural gas or NSPS J quality gas which meets the requirements of Plantwide Condition 10. [Reg.18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

FHR 6. Under the terms of 40 C.F.R. § 60 Subpart Dc-Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, SN-850 and 862 are affected facilities. The permittee shall maintain monthly records of the fuel combusted in SN-850 and 862. [Reg.19.304 and 40 C.F.R. § 60.40c]

FHR 7. All sources listed in Specific Condition FHR 1 are affected facilities under the provisions of 40 C.F.R. § 60, Subpart J-*Standards of Performance for Petroleum Refineries*. As such, these heaters shall burn either pipeline quality natural gas and/or NSPS Subpart J quality gas. They are defined in the subpart as fuel gas combustion devices subject to the Subpart J requirements summarized in Plantwide Condition PW 11. [Reg.19.304 and 40 C.F.R. § 60.100]

FHR 8. The permittee shall operate the #4 Atmospheric Furnace, SN-804, and the #9 Reformer furnace, SN-811, such that NO_x emissions to the atmosphere do not exceed 0.045 lb/MMBtu based on a 3-hour average. [Reg.19.501, Reg.19.901, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]

FHR 9. The permittee shall operate SN-803, SN-805, SN-808, SN-810, and SN-842 such that NO_x emissions to the atmosphere do not exceed 0.035 lb/MMBtu based on a 3 hour average. [Reg.19.901, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 10. The permittee shall demonstrate compliance with the NO_x limits for SN-803, SN-805, SN-808, SN-810, and SN-842 by installing and operating a continuous parameter monitoring system to monitor oxygen concentration in the stack for each heater. The oxygen monitoring system shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter. Lion shall maintain a 3-hour rolling average oxygen concentration between 2% and 7%. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 11. The permittee shall install, certify, calibrate, maintain and operate a CEM system in the SN-811 exhaust stack for the purpose of monitoring NO_x emissions. The data from this monitor shall be recorded and compiled in order to demonstrate compliance with the NO_x limit in Specific Condition FHR 8. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 12. The permittee shall install, certify, calibrate, maintain and operate a CEM system in the #4 Atmospheric Furnace, SN-804, exhaust stack for the purposes of monitoring NO_x emissions. The data from this monitor shall be recorded and compiled in order to demonstrate compliance with the 3 hour average 0.045 lb/MMBtu NO_x limit contained in Specific Condition FHR 8. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of Consent Decree (Civ No. 03-0128)]

FHR 13. The permittee shall not exceed the BACT limits in the following table. Compliance with this condition is demonstrated by complying with Specific Conditions FHR 11, FHR 14, FHR 15, and the NO_x CEMs required for SN-805N. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Combustion Source	Pollutant	Control Technology	BACT Limit lb/MMBtu (3-hour average)
Current #4 Pre-Flash Column Reboiler (SN-803)	PM ₁₀	Good Combustion Practice	0.0075

Combustion Source	Pollutant	Control Technology	BACT Limit lb/MMBtu (3-hour average)
Converted #4 Pre-Flash Column Reboiler (SN-805)	PM ₁₀	Good Combustion Practice	0.0075
No. 4 Atmospheric Furnace (SN-804)	PM ₁₀	Good Combustion Practice	0.0075
	NO _x	Existing NGULNB	See FHR 8
	CO	Good Combustion Practice	0.040
New No. 4 Vacuum Furnace (SN-805N)	PM ₁₀	Good Combustion Practice	0.0075
	NO _x	New NGULNB	0.035
	CO	Good Combustion Practice	0.040

FHR 14. The permittee shall demonstrate compliance with the particulate BACT limits for SN-803, SN-804, SN-805, and SN-805N by the use of NSPS quality gas and the compliance with opacity limits of Specific Condition FHR 5.
 [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

FHR 15. The permittee shall demonstrate compliance with the CO BACT limit for SN-804 and SN-805N by initial and periodic testing every five years thereafter. The compliance with the CO BACT limits in Specific Condition FHR 13 shall be based upon a 3-hour average. The initial test shall take place 180 days after permit issuance. Testing shall be performed in accordance with EPA Reference Method 10 or other pre-approved test method. At the time of testing, the permittee shall operate the source at least within 10% of the maximum rated capacity. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN-809 - #7 FCCU Catalyst Regenerator Stack

Source Description

SN-809 is the exhaust stack from the catalyst regenerator. Hot flue gas leaving the regenerator passes through three sets of cyclones to remove catalyst fines and then is used to produce steam in the waste heat boiler before exiting the stack. This source was installed in 1973. Previously permitted source, SN-848, the vent system for two storage bins used to store catalyst in the catalytic cracking process, has been routed to the wet gas scrubber of the #7 FCCU unit. The #7 FCCU was modified in 2004 to install a wet gas scrubber for the control of PM₁₀ and SO₂ emissions. Simultaneous with the installation of the scrubber, the facility also accepted a limit of 500 ppmdv (1-hour average) and 100 ppmdv (365-day rolling average) as required by the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ. CEMs were installed to monitor the stack concentrations of SO₂, CO, and O₂.

BACT Review

This source underwent a BACT review for particulate and CO as a result of the refinery expansion of the 868-AOP-R5. BACT was demonstrated to be similar controls and emission limits as those defined by the Consent Decree. An additional condensable and filterable PM₁₀ limit was added in 868-AOP-R9.

Specific Conditions

FCCU 1 The permittee shall not exceed the emission rates set forth in the following tables. Compliance with these limits shall be demonstrated by compliance with the throughput limits, monitoring requirements for this source or with other available emissions data for these sources. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
809	#7 Catalyst Regenerator Stack	PM ₁₀	7.5	32.9
		SO ₂	13.3	58.3
		VOC	4.2	18.1
		CO	116.0	101.9
		NO _x	7.7	33.5

FCCU 2 The permittee shall not exceed the emission rates set forth in the following tables. Compliance with these limits shall be demonstrated by compliance with the throughput limits, monitoring requirements for this source or with other available emissions data for these sources. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
809	#7 Catalyst Regenerator Stack	PM	7.5	32.9
		Ammonia	0.6	2.5

FCCU 3 The facility shall not exceed 20% opacity from this source. Compliance with this condition will be demonstrated by compliance with 40 C.F.R. § 60 Subpart Ja, the operation of the wet gas scrubber (WGS). [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

FCCU 4 The permittee shall meet the following outlet emissions limitations. Compliance with these limits in a, c and d will be shown by FCCU 5 as applicable. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E and Paragraphs 11(B) or 11(E), 12(B), 13(B), and 14(B) of the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]

- a. For SO₂:
 - i. No more than 25 ppmvd based on a 365-day rolling average, corrected to 0% oxygen.
 - ii. No more than 50 ppmvd based on a 7-day rolling average, corrected to 0% oxygen
 - iii. The SO₂ limits listed in a.i and a.ii of this Specific Condition do not apply during periods of startup and shutdown of the FCCU, and Malfunction of the either the FCCU or WGS, provided that good air pollution control practices are instituted during such events.
- b. For PM:
 - i. No more than 0.5 pounds of filterable particulate matter (PM) per 1000 pounds of coke burned, on a 3-hour average basis except during periods of startup and shutdown of the FCCU, and Malfunction of the WGS, provided that good air pollution control practices are instituted during such events.
- c. For CO:
 - i. 500 ppmvd corrected to 0% O₂, over a 1-hour average basis.
 - ii. 100 ppmvd corrected to 0% O₂ as a 365-day rolling average basis.
 - iii. The CO limits in c.i. and c.ii. of these Specific Conditions do not apply during periods of startup, shutdown, and Malfunction of the FCCU, provided that good air pollution control practices are instituted during such events.
- d. For NO_x:
 - i. No more than 20 ppmvd based on a 365-day rolling average, corrected to 0% oxygen.
 - ii. No more than 40 ppmvd based on a 24-hour rolling average, corrected to 0% oxygen.
 - iii. The NO_x limits in i. and ii. above do not apply during periods of startup and shutdown of the FCCU, and malfunction of the Lo Tox System, provided that good air pollution practices are instituted during such events.

FCCU 5 On and after December 31, 2004, the permittee shall install, certify, calibrate, maintain and operate a NO_x CEMS, to monitor performance of the FCCU, and subsequently, the Lo Tox System, and SO₂, CO, and O₂, and to report compliance with the terms and conditions of the Consent Decree (CIV. No. 03-1028), as applicable. The CEM shall be operated in accordance with the Department's CEM Conditions, §60.11, §60.13, and appendices A, B, and F. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and the Consent Decree (CIV. No. 03-1028) between Lion Oil, ADEQ, and the US EPA]

FCCU 6 The FCCU is an affected facility under the terms of 40 C.F.R. § 60 Subpart Ja. The requirements of this subpart as they apply to this source are summarized below. [Reg.19.304 and 40 C.F.R. § 60.100a]

- a. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain particulate matter (PM) in excess of 1.0 lb/ton of coke burn-off in the catalyst regenerator. [§ 60.102a(b)(1)(i)]
- b. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain carbon monoxide (CO) in excess of 500 ppmvd, dry basis corrected to 0 percent excess air, on an hourly average basis. [§ 60.102a(b)(4)]
- c. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain SO₂ in excess of 50 ppmvd, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis. [§ 60.102a(b)(3)]
- d. The permittee shall not discharge from the #7 FCCU Catalyst Regenerator Stack (SN-809) any gases which contain NO_x in excess of 80 ppmvd, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis. [§ 60.102a(b)(2)]
- e. As the permittee uses a continuous parameter monitoring system (CPMS) on a wet scrubber, the permittee shall comply with the following control device parameter operating limits.
 - i. The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and
 - ii. The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test. [§ 60.102a(c)]
- f. The permittee shall conduct testing of the #7 FCCU Catalyst Regenerator Stack (SN-809) to show compliance with the PM limit in §60.102a(b). This testing shall be conducted at least once every twelve months. These tests shall be conducted in accordance with Plantwide Condition 3 and as specified below.
 - i. The permittee shall use EPA Reference Method 5 or 5B to determine the PM emission from the #7 FCCU Catalyst Regenerator Stack (SN-809).

The PM tests shall be conducted in accordance with the requirements of §60.104a(d)(4)(i) through (v).

- ii. The permittee shall use Method 1 of Appendix A-1 to part 60 for sample and velocity traverses, Method 2 for velocity and volumetric flow rate, and Method 3, 3A, or 3B of Appendix A-2 to part 60 for gas analysis. The ANSI/ASME PTC 19.10-1981 is an acceptable alternative to Method 3B.
 - iii. The permittee shall adjust the measured pollutant concentrations to 0 percent excess air or 0 percent O₂ using Equation 6 in §60.102a(d)(8).
 - iv. The permittee shall establish the limits for the control device operating parameters required in §60.102a(c) based on the performance test results according to the following procedures: Reduce the parameter monitoring data to hourly averages for each test run and determine the hourly average operating limit for each required parameter as the average of the three test runs. [§ 60.104a(b)]
- g. The permittee shall for the #7 FCCU Catalyst Regenerator Stack (SN-809), install, operate, and maintain continuous parameter monitoring system to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate.
- i. As an alternative to a CPMS the permittee must comply with the requirements in either paragraph §§ 60.105a(b)(1)(ii)(A) or 60.105a(b)(1)(ii)(B).
 - ii. The permittee shall install, operate, and maintain the CPMS according to the manufacturer's specifications and requirements.
 - iii. The permittee shall determine and record the average coke burn-off rate and hours of operation for the #7 FCCU Catalyst Regenerator Stack (SN-809) using the procedures in § 60.104a(d)(4)(iii). [§ 60.105a(b)(1)]
- h. The permittee shall for use in determining the coke burn-off rate for the #7 FCCU Catalyst Regenerator Stack (SN-809) install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO₂, O₂, (dry basis), and if needed, CO in the exhaust gasses prior to any control or energy recovery system that burns auxiliary fuels.
- i. The permittee shall install, operate, and maintain each monitor according to Performance Specification 3 of appendix B to 40 C.F.R. § 60. Performance evaluations of each CO₂, O₂, and CO monitor shall be conducted according to Performance Specification 3. Method 3 of appendix A-3 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy evaluations.
 - ii. The permittee shall comply with the quality assurance requirements of procedure 1 of appendix F to 40 C.F.R. § 60, including quarterly accuracy determinations for CO₂ and CO monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift checks. [§ 60.105a(b)(2)]

- i. The permittee shall for the #7 FCCU Catalyst Regenerator Stack (SN-809) install, operate, calibrate, and maintain an instrument for continuously monitoring the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.
- i. The permittee shall install, operate, and maintain each NO_x monitor according to Performance Specification 2 of appendix B to 40 C.F.R. § 60. The span value of this NO_x monitor is to be 200 ppmv NO_x.
- ii. The permittee shall conduct performance evaluations of each NO_x monitor according to the requirements in 60.13(c) and Performance Specification 2 of appendix B to 40 C.F.R. § 60. Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10 – 1981 is an acceptable alternative to EPA method 7 or 7C.
- iii. The permittee shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to 40 C.F.R. § 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.
- iv. The permittee shall performance evaluations of each O₂ monitor according to the requirements in 60.13(c) and Performance Specification 3 of appendix B to 40 C.F.R. § 60. Methods 3, 3A, or 3B of appendix A-2 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10 – 1981 is an acceptable alternative to EPA method 3B.
- v. The permittee shall comply with the quality assurance requirements of procedure 1 of appendix F to 40 C.F.R. § 60 for each NO_x and O₂ monitor, including quarterly accuracy determinations for NO_x monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift checks. [§ 60.105a(f)]
- j. The permittee shall for the #7 FCCU Catalyst Regenerator Stack (SN-809) install, operate, calibrate, and maintain an instrument for continuously monitoring the concentration by volume (dry basis, 0 percent excess air) of SO₂ emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.
- i. The permittee shall install, operate, and maintain each SO₂ monitor according to Performance Specification 2 of appendix B to 40 C.F.R. § 60. The span value of this SO₂ monitor is to be 200 ppmv SO₂.
- ii. The permittee shall performance evaluations of each SO₂ monitor according to the requirements in 60.13(c) and Performance Specification 2 of appendix B to 40 C.F.R. § 60. Methods 6, 6A, or 6C of appendix A-4 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy

- evaluations. The method ANSI/ASME PTC 19.10 – 1981 is an acceptable alternative to EPA method 6 or 6A.
- iii. The permittee shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to 40 C.F.R. § 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.
 - iv. The permittee shall performance evaluations of each O₂ monitor according to the requirements in 60.13(c) and Performance Specification 3 of appendix B to 40 C.F.R. § 60. Methods 3, 3A, or 3B of appendix A-2 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10 – 1981 is an acceptable alternative to EPA method 3B.
 - v. The permittee shall comply with the quality assurance requirements of procedure 1 of appendix F to 40 C.F.R. § 60 for each SO₂ and O₂ monitor, including quarterly accuracy determinations for SO₂ monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift checks. [§ 60.105a(g)]
- k. The permittee shall for the #7 FCCU Catalyst Regenerator Stack (SN-809) install, operate, calibrate, and maintain an instrument for continuously monitoring the concentration by volume (dry basis, 0 percent excess air) of CO emissions into the atmosphere.
- i. The permittee shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to 40 C.F.R. § 60. The span value of this monitor is to be 1000 ppm CO.
 - ii. The permittee shall performance evaluations of each CO monitor according to the requirements in 60.13(c) and Performance Specification 4 or 4A of appendix B to 40 C.F.R. § 60. Methods 10, 10A, or 10B of appendix A-4 of 40 C.F.R. § 60 shall be used for conducting the relative accuracy evaluations. [§ 60.105a(h)]
- l. For the purpose of reports required by 60.7(c), periods of excess emissions for the #7 FCCU Catalyst Regenerator Stack (SN-809) are defined as specified below.
- i. For the CPMS, all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under 60.105a(b)(1), fall below the levels established during the performance test for the #7 FCCU Catalyst Regenerator Stack (SN-809).
 - ii. All rolling 7-day periods during which the average concentration of NO_x as measured by the NO_x CEMS under 60.105a(f) exceeds 80 ppmv for the #7 FCCU Catalyst Regenerator Stack (SN-809).
 - iii. All 7-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS under 60.105a(g) exceeds 50 ppmv, and all

rolling 365-day periods during which the average concentration of COT as measured by the SO₂ CEMS exceeds 25 ppmv.

- iv. All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under 60.105a(h) exceeds 500 ppmv. [§ 60.105a(i)]
- m. The permittee shall comply with the notification, recordkeeping, and reporting requirements of 40 C.F.R. 60.7 and other requirements specified by 40 C.F.R. § 60.108. [§ 60.108a(a)]
- n. The permittee shall notify the administrator of the specific monitoring provisions of 60.105(a) with which they seek to comply. Notifications shall be submitted with the notification of initial startup required by 60.7(a)(3). [§ 60.108a(b)]
- o. The permittee must maintain records for the #7 FCCU Catalyst Regenerator Stack (SN-809) of the average coke burn-off rate and hours of operation. [§ 60.108a(c)]
- p. The permittee must for #7 FCCU Catalyst Regenerator Stack (SN-809) submit an excess emission report for all periods of excess emissions according to the requirements of 60.7(c) except that the report shall contain the following information:
 - i. The date the exceedance occurred;
 - ii. An explanation of the exceedance;
 - iii. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system;
 - iv. A description of the action taken, if any;
 - v. A root-cause summary report that provides the information described in paragraph 60.108a(e)(6) for all discharges for which a root-cause analysis was required by 60.103a(a)(4) and 60.103a(b);
 - vi. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with the operation of the control system and affected facility before and following the period of data unavailability; and
 - vii. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report. [§ 60.108a(d)]

FCCU 7 All CEMS shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's standards. A copy of these standards has been attached in the appendices.

[Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

FCCU 8 SN-809 (the FCCU) is an affected facility under the terms of 40 C.F.R., Part 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The applicable requirements of this subpart are summarized in Plantwide Condition PW 12. [Reg.19.304 and 40 C.F.R. § 63.1561]

BACT Requirements

FCCU 9 The permittee shall not exceed the BACT limits set forth in the following table. Compliance with this condition will be shown by complying with Specific Conditions FCCU 4, FCCU 5, and FCCU 7. [Reg.19.901 *et seq.* and 40 C.F.R. § 52 Subpart E]

Pollutant	Emission Limit	Compliance Demonstration Method	Control Technology
Filterable PM ₁₀	0.50 lb/1,000 lb of coke burn-off	EPA Reference Method 5B	Wet Gas Scrubber
Filterable and Condensable PM ₁₀	1.0 lb/1,000 lb of coke burn-off	EPA Reference Method 5B and Method 202	Wet Gas Scrubber
CO	100 ppmdv (365-day rolling average)	CO CEMS	High Temperature Regeneration
	500 ppmdv (1-hr average)		

FCCU 10 The permittee shall test particulate emissions at the #7 FCCU Catalyst Regenerator Stack, SN-809, every five years after the previous performance tests including both filterable and condensable particulate. The testing shall be conducted in accordance with EPA Reference Method 5B and Method 202. During the test, the permittee shall operate the source within 10 percent of the maximum coke burn rate. [Reg.19.901 and Reg.19.702 of Regulation 19 and 40 C.F.R. § 52 Subpart E]

FCCU 11 The permittee shall not exceed an hourly coke burn-off rate of 11,700 lb coke burn-off per hour until testing at a higher rate can be completed. Compliance with this limit will be shown by the record keeping of coke burn-off rate required in Specific Condition FCCU 6. The permittee may exceed this limit during testing to establish a new maximum rate as long as they do not exceed 15,000 lb coke burn-off per hour. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

ALTERNATE OPERATING SCENARIO - FCCU PORTABLE AIR COMPRESSORS

During periods of startup, shutdown and/or malfunction, or for purposes of conducting scheduled or emergency maintenance on the fluid catalytic cracking unit when the electric air compressors are not operating, Lion Oil may utilize portable, diesel-fired air compressors.

Specific Conditions

- FCCU 12 The permittee shall not operate the portable compressors for more than 1,560,000 horsepower-hours on an annual basis. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- FCCU 13 Lion Oil will record the hours of operation of the air compressors, on a twelve-month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

SN-844 - SRP Sulfur Recovery Plant Incinerator

Source Description

The Sulfur Recovery Plant Incinerator is a 20.0 MMBtu/hr incinerator used to incinerate gases from the sulfur recovery plant. It is fueled by pipeline quality natural gas. It was installed in 1994. The incinerator is used to control emissions from the 3 stage sulfur recovery unit (SRU) which is also subject to Subpart J. The SRP is rated at 120 long tons per day (LTD).

Specific Conditions

SRP 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN-844 shall be demonstrated by compliance with Subpart J, the fuel and Btu limits for these sources or with other available emissions data for these sources. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
844	Sulfur Recovery Plant Incinerator	PM ₁₀	12.0	52.7
		SO ₂	19.1	53.4
		VOC	1.5	6.6
		CO	8.1	35.6
		NO _x	6.0	26.4

SRP 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with the limits for SN-844 shall be demonstrated by compliance with Subpart J, the fuel and Btu limits for these sources or with other available emissions data for these sources. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
844	Sulfur Recovery Plant Incinerator	PM	12.0	52.7
		Ammonia	0.1	0.1
		H ₂ S	0.6	2.3

SRP 3 Any emissions to the atmosphere from any Claus sulfur recovery plant using an oxidation control system or a reduction control system followed by incineration shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated by SO₂ emissions data recorded per Subpart J. [Reg.19.304 and 40 C.F.R. § 60.104(a)(2)(i)]

SN #	Source Description	Pollutant	ppm by volume
844	Sulfur Recovery Plant Incinerator	SO ₂ dry basis	250 (Rolling 12-hour)

SRP 4 The facility shall use only pipeline quality natural gas as fuel for SN-844. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

- SRP 5 The permittee shall not emit visible emissions from SN-844 which exceed 20% opacity. Compliance with this condition will be shown by compliance with Specific Conditions SRP 4. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]
- SRP 6 The SO₂ and O₂ CEMs in use at SN-844 shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's conditions. CEM data shall be submitted in ppm, lb/hr, and tpy for SN-844. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- SRP 7 SN-844 is an affected facility under the provision of 40 C.F.R. § 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The UUU requirements are summarized in Plantwide Condition PW 12. [Reg.19.304 and 40 C.F.R. § 63 Subpart UUU]
- SRP 8 The Sulfur Recovery Unit (SRU) is an affected facility under the provision of 40 C.F.R. 60, Subpart J – Standards of Performance for Petroleum Refineries. The applicable Subpart J requirements are summarized below. [Reg.19.304 and 40 C.F.R. § 60 Subpart J]
- a. The permittee shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. The monitor shall be operated as follows: [§ 60.105(a)(5)]
 - i. The span values for this monitor are 500 ppm SO₂ and 25 percent O₂. [§ 60.105(a)(5)(i)]
 - ii. The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. [§ 60.105(a)(5)(ii)]
 - b. The permittee shall report excess emissions for all 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air). [§ 60.105(e)(4)(i)]
 - c. For any periods for which sulfur dioxide or oxides emissions data are not available, the permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability. [§ 60.107(d)]
 - d. The permittee shall submit a report on the SO₂ CEM system which contains all of the information required by § 60.107(d). This report shall be submitted to the Department in accordance with the Department CEM Conditions. [§ 60.107(e)]

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

- e. The owner or operator of the facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. [§ 60.107(f)]

SN-821a, 821b, 821c - Refinery Boilers (Three Boilers)

Source Description

Three refinery boilers were installed at the facility as part of the boiler replacement project required by the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, ADEQ, and the US EPA. The total rated heat input capacity for all three boilers are 605 MMBtu/hr on an annual average basis. Individually the boilers each operate at a maximum of 221.8 MMBtu/hr for a total maximum heat input capacity of 665.5 MM Btu/hr. These boilers are permitted to burn NSPS Subpart J quality gas, or #2 fuel oil. Each of the boilers utilizes next-generation ultra-low-NO_x burners for NO_x emission control.

Regulations

All three of the refinery boilers are subject to each of the following regulations: 40 C.F.R. § 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 C.F.R. § 60 Subpart J – Standards of Performance for Petroleum Refineries.

The emission limitations established for this source were relied upon in a PSD netting analysis. Future increases in these permitted levels may trigger PSD review for these sources.

Specific Conditions

BOI 1 The listed sources shall not exceed the emission rates set forth in the following table. The limits given in this table represent the combined emissions from all three boiler exhaust stacks. Compliance with these limits shall be demonstrated by compliance with Specific Conditions #BOI 2, #BOI 6, #BOI 7, #BOI 8, #BOI 10 #BOI 12, #BOI 13 or with other available emissions data for these sources. The emission rates in the table below for #2 fuel oil combustion do not allow for the facility to make modifications in order to combust fuel oil. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Source Description	Pollutant	lb/hr	tpy
821	Three Boilers - burning NSPS Subpart J quality gas	PM ₁₀	7.8	---
		SO ₂	22.4	---
		VOC	9.8	---
		CO	474.2	---
		NO _x	23.3	---
821	Three boilers – burning #2 fuel oil	PM ₁₀	15.7	---
		SO ₂	37.3	---
		VOC	20.0	---
		CO	474.2	---
		NO _x	66.6	---

SN	Source Description	Pollutant	lb/hr	tpy
821	Refinery Boilers - Annual Emission Limitations (regardless of fuel)	PM ₁₀	---	31.1
		SO ₂	---	81.3
		VOC	---	39.1
		CO	---	123.2
		NO _x	---	58.0

BOI 2 The listed sources shall not exceed the emission rates set forth in the following table. The limits given in this table represent the combined emissions from all three boiler exhaust stacks. Compliance with these limits shall be demonstrated by compliance with Specific Conditions #BOI 2, #BOI 6, #BOI 7, #BOI 8, #BOI 10, #BOI 12, #BOI 13 or with other available emissions data for these sources. The emission rates in the table below for #2 fuel oil combustion do not allow for the facility to make modifications in order to combust fuel oil. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Source Description	Pollutant	lb/hr	tpy
821	Three Boilers - burning NSPS Subpart J quality gas	PM	7.8	---
		Ammonia	2.1	
		H ₂ S	0.2	
821	Three boilers – burning #2 fuel oil	PM	15.7	---
		Ammonia	2.1	
		H ₂ S	0.2	
821	Refinery Boilers - Annual Emission Limitations (regardless of fuel)	PM	---	31.1
		Ammonia		8.4
		H ₂ S		0.6

BOI 3 The facility shall not exceed a total combined annual firing rate of 5,314,320 MMBtu during any consecutive 12-month period at the refinery boilers (SN-821a, 821b, and 821c combined). [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

BOI 4 Total maximum heat input capacity of the boilers (SN-821a, b, and c) shall not exceed 665.5 MMBtu/hr. Compliance shall be verified by totaling nameplate heat input capacity. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

BOI 5 The facility shall analyze the Btu content of all fuels fired in the refinery boilers on a monthly basis. These records shall include the fuel combusted and heat duty (amount of fuel x heating value). The records of Btu content shall be maintained on site and submitted in accordance with General Provision #7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

BOI 6 The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or refinery fuel gas which meets the requirements of Plantwide Condition 10. [Reg.18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

- BOI 7 The facility shall not exceed 20% opacity from the refinery boilers (SN-821a, b, or c) when burning fuel oil. Compliance with this condition shall be demonstrated by The COMs data in condition BOI 13c. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]
- BOI 8 The facility shall use only pipeline quality natural gas or NSPS Subpart J quality gas as fuel for the refinery boilers (SN-821). In the event of pipeline quality natural gas curtailment, emergency, or upset conditions as set forth in Chapter 6 of Regulation 19, the boilers may be fired with fuel oil if fuel gas is unavailable. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- BOI 9 The permittee shall not exceed an NO_x emission rate of 0.035 lb/MMBtu based on a rolling 3-hour average from any of the three refinery boilers (SN-821a, 821b and 821c). [Reg.19.501, 40 C.F.R. § 52 Subpart E, and Paragraph 16(D) of the consent agreement between Lion Oil, the US EPA, and ADEQ]
- BOI 10 In the event that fuel oil is used at this source, the facility shall maintain monthly records of fuel oil usage including the amount of fuel oil used and the sulfur content of the fuel oil. Records shall be maintained on site and submitted in accordance with General Provision 7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- BOI 11 The permittee shall install, operate, and maintain continuous emission monitoring (CEM) systems on each of the refinery boiler stacks (SN-821a, 821b, 821c) to monitor stack gas concentrations of CO and NO_x. These CEM systems shall comply with the Department's CEM Conditions. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- BOI 12 The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable provisions of 40 C.F.R. § 60, Subpart J-Standards of Performance for Petroleum Refineries. They are defined in the subpart as fuel gas combustion devices. The applicable requirements are summarized in Specific Condition #BOI 8 and Plantwide Condition #PW 11. [Reg.19.304 and 40 C.F.R. § 60.100]
- BOI 13 The refinery boilers (SN-821a, 821b, 821c) are subject to and shall comply with all applicable requirements of 40 C.F.R. § 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The applicable requirements are summarized below. [Reg.19.304 and 40 C.F.R. § 60.40b]
- a. Affected facilities which also meet the applicability requirements under Subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under NSPS Subpart Db and the sulfur dioxide standards under subpart J (§ 60.104). [§ 60.40b(c)]
 - b. On and after the date on which the initial performance test is completed or is required to be completed under 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute

- average), except for one 6-minute period per hour of not more than 27 percent opacity. [§ 60.43b(f)]
- c. The owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. [§ 60.48b(a)]
 - d. Except as provided under § 60.44b(k) and (l), on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of §§ 60.44b and that combusts oil or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO₂) in excess of 0.1 lb/MMBtu for distillate oil or gas-fired low heat release rate boilers or 0.2 lb/MMBtu for distillate oil or gas-fired high heat release rate boilers. [§§ 60.44b(a), (l)(1), and (l)(2)]
 - e. The nitrogen oxide standards under 60.44b apply at all times including periods of startup, shutdown, or malfunction. [§ 60.44b(h)]
 - f. Compliance with the emission limits under § 60.44b is determined on a 30-day rolling average basis. Compliance shall be demonstrated by using the data collected to demonstrate compliance with Specific Condition BOI 1. If the data collected to demonstrate compliance with Specific Condition does not meet the requirements of 60.44b, then Lion may be required to produce records to demonstrate compliance on a 30-day rolling average basis. [§ 60.44b(i)]
 - g. Compliance with the NO_x standard under § 60.44b shall be determined through performance testing as specified by § 60.46b(e). [§ 60.46b(c)]
 - h. To determine compliance with the emission limits for nitrogen oxides required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.48(b). [§ 60.46b(e)]
 - i. The permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere. [§ 60.48b(b)(1)]
 - j. The continuous monitoring systems required under § 60.48b(b)(1) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. [§ 60.48b(c)]
 - k. The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph § 60.48b(b)(1) and required under § 60.13(h) shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall

- be calculated using the data points required under § 60.13(b). At least 2 data points must be used to calculate each 1-hour average. [§ 60.48b(d)]
- l. The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. [§ 60.48b(e)]
 - m. The span value for NO_x must be determined according to § 60.48b(e)(2). All span values are rounded to the nearest 500 ppm. Alternatively ADEQ has approved a span value of 100 ppm for the boiler NO_x CEMS. [§ 60.48b(e)(2 and (3))]
 - n. When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days. [§ 60.48b(f)]
 - o. The permittee shall submit notification of the date of initial startup, as provided by § 60.7. The notification shall include:
 - i. The design heat input capacity of the affected facility and identification of the fuels to be combusted in the facility, and [§ 60.49b(a)(1)]
 - ii. The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired. [§ 60.49b(a)(2)]
 - p. The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of 40 C.F.R. § 60. [§ 60.49b(b)]
 - q. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [§ 60.49b(d)]
 - r. The owner or operator of an affected facility subject to the nitrogen oxides standards under § 60.44b shall maintain records of the following information and submit the following in required semi-annual reports for each steam generating unit operating day: [§ 60.49b(g) and (i)]
 - i. Calendar date
 - ii. The average hourly nitrogen oxides emission rates (expressed as NO₂) (ng/J or lb/million Btu heat input) measured or predicted.

- iii. The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.
- iv. Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.
- v. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.
- vi. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.
- vii. Identification of “F” factor used for calculations, method of determination, and type of fuel combusted.
- viii. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
- ix. Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.
- x. Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.
- s. The permittee shall submit excess emission reports for any excess emissions that occurred during the reporting period. For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under § 60.46b(e), which exceeds the applicable emission limit in § 60.44b. [§ 60.49b(h)]
- t. All records required under 60.44b shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record. 60.44b (o)]
- u. The reporting period for the reports required under NSPS Subpart Db is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. The 6 month period may coincide with Lion’s current semi-annual monitoring reporting (January 1st – June 30th and July 1st – December 31st). [§ 60.49b(w)]

SN-822 - High Pressure Flare
SN-823 - Low Pressure Flares

Source Description

SN-822 and SN-823 are steam assisted flares used to provide for the safe disposal of hydrocarbon- vapors discharged from refinery process units from upset conditions, startups, shutdowns and malfunctions. The gases that will be routinely combusted in the flares are pilot gas, purge gas, and NSPS Subpart Ja quality gas from the fuel gas system.

SN-822 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the high pressure flare. It was installed in 1979.

SN-823 maintains a pilot light designed at 1.5 MM Btu/hr and is known as the low pressure flare. It was installed in 1974.

A Flare Gas Recovery System (FGRS) has been installed at the facility. The purpose of the FGRS is to recover refinery gases. The FGRS compresses the flare gases and allows them to be processed either in the fuel gas system or through the gas plant. When the fuel gas produced exceeds refinery demand, excess gas meeting the requirements of 40 C.F.R., Part 60, Subpart J, may be routed to the flares. The FGRS is not a source of emissions.

Specific Conditions

FLA 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by operation of the flare gas recovery system and by compliance with the fuel and flow rate limits of this section. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/day	tpy
822, 823	Both Flares	PM ₁₀	99	4.0
		SO ₂	484	19.6
		VOC	842	34.1
		CO	2,220	89.9
		NO _x	612	24.8
		Ammonia	0.1	0.1
		H ₂ S	0.1	0.1

FLA 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by operation of the flare gas recovery system and by compliance with the fuel and flow rate limits of this section. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/day	tpy
822, 823	Both Flares	PM	99	4.0

- FLA 3 The flare gas recovery system shall be in operation at all times. If the flare gas recovery system is not in operation, Lion Oil is in compliance with this condition provided that the flare is operated and the emission limits in Specific Condition FLA 1 are not exceeded. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- FLA 4 The flares shall be operated as required in § 60.18. These requirements are summarized below. [Reg.19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- a. The flares shall be operated with a flame present at all times as required by § 60.18(c)(2).
 - b. The facility shall monitor the flares to ensure they are operated and maintained in conformance with their designs in accordance with § 60.18(d).
 - c. The flares shall be operated at all times when emissions may be vented to them as required by § 60.18(e).
- FLA 5 The flares shall be operated with no visible emissions, except for periods not to exceed a total of five minutes during any consecutive two hour period, when the flares may have emissions not to exceed 60% opacity. [Reg.19.304 and Reg.19.503 and 40 C.F.R. § 60.18(c)(1)]
- FLA 6 The high and low-pressure flares (SN-822 and SN-823) are affected facilities under the terms of 40 C.F.R. § 60 Subpart Ja. Pipeline quality natural gas meets the requirements of Subpart Ja. [Reg.19.304 and 40 C.F.R. § 60.100]
- FLA 7 The total flow of pilot gas, purge gas and excess NSPS Ja quality gas to the flares shall be limited to 6 MM scf/day and a total limit of 486 MM scf per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- FLA 8 Records for the rolling annual flow rate in Specific Condition FLA 7 shall be maintained on a twelve-month rolling basis, updated monthly. Records shall be maintained to demonstrate compliance with the daily limit in Specific Condition FLA 7. Such records shall be maintained on-site and the 12-month rolling totals shall be submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]
- FLA 9 The permittee shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this §60.103a. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this §60.103a. The permittee must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of §60.103a. [Reg.19.304 and 40 C.F.R. Subpart Ja]
- FLA 10 The permittee shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this §60.103a.

(1) For a flare:

- (i) Any time the SO₂ emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or
- (ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m³) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of §60.103a, in any 24-hour period; or
- (iii) If the monitoring alternative in §60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of §60.103a. [Reg.19.304 and 40 C.F.R. Subpart Ja]

FLA 11 A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of §60.103a. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of §60.103a.

- (1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of §60.103a for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.
- (2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of §60.103a, a single root cause analysis and corrective action analysis may be conducted.
- (3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of §60.103a were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in §60.108a(c)(6) and reported as described in §60.108a(d)(5).
- (4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) §60.103a in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.
- (5) Except as provided in paragraph (d)(4) of §60.103a, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of §60.103a for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted. [Reg.19.304 and 40 C.F.R. Subpart Ja]

FLA 12 The high and low pressure flares (SN-822 and SN-823) are affected facilities under the NSPS, 40 C.F.R. Part 60 and are subject to and required to comply with the requirements of 40 C.F.R. Part 60, Subpart A. [Reg.19.304 and 40 C.F.R. Subpart Ja]

SN-831 -#9 Continuous Catalyst Regenerator (CCR)

Source Description

SN-831 is a regenerator used to continuously burn off the coke deposit from the catalyst, and restore catalyst activity, selectivity, and stability. This source was installed in 1991. Usage of a new catalyst was implemented in 2003/2004 in order to produce additional hydrogen for the No. 8 and No. 10 hydrotreating processes.

Specific Conditions

- CCR 1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limit for this source. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
831	#9 Continuous Catalyst Regenerator	PM ₁₀	2.0	8.8
		SO ₂	2.0	8.8
		VOC	2.0	8.8
		CO	2.6	11.4
		NO _x	2.0	8.8

- CCR 2. The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limit for this source. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
831	#9 Continuous Catalyst Regenerator	PM	2.0	8.8

- CCR 3. The facility shall not exceed 20% opacity from the SN-831. Compliance with this condition shall be demonstrated by compliance with Plantwide Condition PW 11. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

- CCR 4. SN-831 (the CCR) is an affected facility under the terms of 40 C.F.R., Part 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The applicable requirements of this subpart are summarized in Plantwide Condition PW 12. [Reg.19.304 and 40 C.F.R. § 63.1561]

SN-832 - 47 Asphalt Tank Heaters
Source Description

SN-832 is comprised of 47 tank heaters with a total heat input capacity of 99.3 MMBtu/hr (nominal design). The heaters are used to maintain elevated temperatures of stored asphalt products so that the material will flow and not solidify. The heaters included in this source grouping are described in the following table.

Tank SN	Year Installed	# of Heaters	MMBtu/hr per heater	total MMBtu/hr per tank
T-39	pre-1981	2	3.0	6.0
T-40	1988	1	2.3	2.3
T-41	1991	1	2.3	2.3
T-78	1999	3	0.68	2.1
T-107	1987	4	2.75	11.0
T-118	1987	4	2.75	11.0
T-219	1968	4	1.8	7.2
T-348	1968	2	2.3	4.6
T-524	1986	4	2.3	9.2
T-530	1986	4	2.3	9.2
T-544	1991	2	0.5	1.0

Because the combined emissions from these sources emit more than 10 tpy of a single criteria pollutant, they cannot be classified as insignificant emission sources. These sources have been permitted at full capacity and fire only NSPS Subpart J quality gas.

Specific Conditions

ASP 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by permitting these sources at full capacity and compliance with NSPS Subpart J. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
832	47 Asphalt Tank Heaters	PM ₁₀	1.0	4.4
		SO ₂	4.3	14.7
		VOC	1.0	4.4
		CO	10.6	35.9
		NO _x	12.9	43.6

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

ASP 2 The permittee shall not exceed the emission rates set forth in the following table.
Compliance with these limits shall be demonstrated by permitting these sources at full capacity and compliance with NSPS Subpart J. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
832	47 Asphalt Tank Heaters	PM	1.0	4.4
		Ammonia	0.5	1.4
		H ₂ S	0.1	0.2

ASP 3 The facility shall not exceed 5% opacity from the sources in this section. Compliance with this limit shall be demonstrated by burning pipeline quality natural gas or refinery fuel gas which meets the requirements of PW 11. [Reg.18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

ASP 4 The facility shall burn only pipeline quality natural gas or NSPS Subpart J quality gas at the sources included in SN-832. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

ASP 5 The Asphalt Heaters (SN-832) are an affected facility under the provisions of 40 C.F.R. § 60, Subpart J-Standards of Performance for Petroleum Refineries. It is defined in the subpart as a fuel gas combustion device. They are defined in the subpart as fuel gas combustion devices subject to the Subpart J requirements summarized in Plantwide Condition PW 11. [Reg.19.304 and 40 C.F.R. § 60.100]

SN-841A – G398TA Air Compressor

Source Description

All of the following described sources are pipeline quality natural gas compressor engines used to move gases within refinery plant operations. They are all fueled by pipeline quality natural gas.

Specific Conditions

AIR 1 The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in the table below. Compliance with these limits shall be demonstrated by compliance with the operation and testing limits of this section. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
841A	G3512TA Air Compressor	PM ₁₀	0.3	1.1
		SO ₂	0.1	0.1
		VOC	1.1	3.6
		CO	7.0	23.7
		NO _x	4.7	15.8

AIR 2 The permittee shall not exceed the emission rates set forth in the following tables. The permittee shall comply with the emission limits contained in the table below. Compliance with these limits shall be demonstrated by compliance with the operation and testing limits of this section. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
841A	G3512TA Air Compressor	PM	0.3	1.1
		Ammonia	1.4	5.9

AIR 3 The facility shall not exceed 5% opacity from SN-841A. Compliance with this limit shall be demonstrated by burning only pipeline quality natural gas. [Reg.18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

AIR 4 The facility shall use only pipeline quality natural gas as fuel for the compressors within this section. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

AIR 5 Within every five years of the previous test, the permittee shall simultaneously conduct tests for CO and NO_x SN-841A in accordance with Plantwide Condition #3. EPA Reference Method 7E (or other approved method) shall be used to test NO_x for the reciprocating engines and EPA reference Method 10 (or other approved method) shall be used to determine CO. EPA Reference Method 19 shall be used to convert test results to mass emission rates. The results of this testing shall be maintained on-site, and shall be submitted to the Department in accordance with General Provision #7. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]

AIR 6 The G3512TA Air Compressor (SN-841A) is subject to and shall comply with all applicable provisions of 40 C.F.R. § 63, Subpart ZZZZ. SN-841A is a new four-stroke rich burn (4SRB) compressor. The compliance requirements of this subpart as they apply to this source are summarized below. [Reg.19.304 and 40 C.F.R. § 63.6585]

- a. The permittee shall comply with the applicable emission limitations in Table 1a of Subpart ZZZZ and the operating limits in Table 1b of Subpart ZZZZ upon startup of the affected source. [40 C.F.R. § 63.6600(a)]
 - i. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15% oxygen. [40 C.F.R. § 63, Table 1a]
 - ii. Maintain the catalyst so that the pressure drop across the catalyst does not change by more than two inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test. [40 C.F.R. § 63, Table 1b]
 - iii. Maintain the temperature of the RICE exhaust so that the catalyst inlet temperature is between 750 °F to 1250°F. [40 C.F.R. § 63, Table 1b]
 - iv. Comply with an operating limitations approved by the Administrator. [40 C.F.R. § 63, Table 1b]
- b. The permittee shall comply with the applicable emission limitations and operating limitations in Subpart ZZZZ at all times, except during periods of startup, shutdown, and malfunction. [40 C.F.R. § 63.6605(a)]
- c. The permittee shall operate and maintain the stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction. [40 C.F.R. § 63.6605(b)]
- d. Initial compliance shall be demonstrated via the initial performance test or other initial compliance demonstrations in Table 4 of Subpart ZZZZ, no later than 180 days after startup of the source according to the provisions of § 63.7(a)(2) and Table 5 of Subpart ZZZZ. [40 C.F.R. § 63.6610(a) and § 63.6630(a)]
 - i. During the initial performance test, the permittee shall establish each applicable operating limitation in Table 1b of Subpart ZZZZ. [40 C.F.R. § 63.30(b)]
 - ii. Complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust, the permittee must: [40 C.F.R. § 63, Table 4]
 1. Select the sampling port location and the number of traverse points using Method 1 or 1A of 40 C.F.R. § 60, Appendix A § 63.7(d)(1)(i). If using a control device, the sampling site must be located at the outlet of the control device.
 2. Determine the O₂ concentration of the stationary RICE exhaust at the sampling port location using Method 3 or 3A or 3B of 40

- C.F.R. § 60, Appendix A. Measurements to determine O₂ concentration must be made at the same time and location as the measurements for formaldehyde concentration.
3. Measure moisture content of the stationary RICE exhaust at the sampling port location using Method 4 of 40 C.F.R. § 60, Appendix A, or Test Method 320 of 40 C.F.R. § 63, Appendix A, or ASTM D 6348-03.
 4. Measure formaldehyde at the exhaust of the stationary RICE using Method 320 or 323 of 40 C.F.R. § 63, Appendix A; or ASTM D6348-03. Formaldehyde concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
- iii. Complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust, the permittee has demonstrated initial compliance if : [40 C.F.R. § 63, Table 5]
1. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation.
 2. The permittee has installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), and
 3. The permittee has recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
- e. The permittee shall conduct subsequent performance tests as specified in Table 3 of Subpart ZZZZ. [40 C.F.R. § 63.6615]
- i. Subsequent performance tests must be conducted semiannually. [40 C.F.R. § 63, Table 5]
 - ii. After the permittee has demonstrated compliance for two consecutive tests, then the permittee may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent performance test indicate the stationary RICE is not in compliance with the formaldehyde emission limitation, or the permittee has deviated from any operating limitations, the permittee must resume semiannual performance tests. [40 C.F.R. § 63, Table 5]
- f. The permittee shall install, operate, and maintain each CMPS to continuously monitor catalyst inlet temperature, required in Table 6 to Subpart ZZZZ according to the requirements in § 63.8. [40 C.F.R. § 63.6625(b)]
- g. The permittee shall monitor continuously at all times that the stationary RICE is operating except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks,

and required zero and span adjustments). The permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. The permittee must, however, use all the valid data collected during all other periods. [40 C.F.R. § 63.6635(b) and (c)]

- h. The permittee shall demonstrate continuous compliance with each applicable emission limitation and operating limitation in Table 1a and 1b and of Subpart ZZZZ according to methods specified in Table 6 of Subpart ZZZZ. [40 C.F.R. § 63.6640(a)]
 - i. Conducting semiannual performance tests for formaldehyde to demonstrate that emissions remain at or below the formaldehyde concentration limit; [40 C.F.R. § 63, Table 6]
 - ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); [40 C.F.R. § 63, Table 6]
 - iii. Reducing these data to 4-hour rolling averages; [40 C.F.R. § 63, Table 6]
 - iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; [40 C.F.R. § 63, Table 6]
 - v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test. [40 C.F.R. § 63, Table 6]
- i. The permittee shall report each instance in which the permittee did not meet an applicable emission limitation or operating limitation in Tables 1a and 1b of Subpart ZZZZ. These instances are deviations from the emission and operating limitations in Subpart ZZZZ. These deviations must be reported according to the requirements in 63.6650. If the permittee changes catalyst, the permittee must reestablish the values of the operating parameters measured during the initial performance test. When the permittee reestablishes the values of their operating parameters, the permittee must also conduct a performance test to demonstrate that the permittee is meeting the required emission limitation applicable to their stationary RICE. [40 C.F.R. § 63.6640(b)]
- j. Consistent with 63.6(e) and 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if the permittee demonstrates to the Administrator's satisfaction that the source was operating in accordance with 63.6(e)(1). As a new source, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. [40 C.F.R. § 63.6640(d)]
- k. The permittee shall report each instance in which the source did not meet the requirements in Table 8 of Subpart ZZZZ that apply. [40 C.F.R. § 63.6640(e)]

- l. The permittee shall submit all of the applicable notifications in 63.7(b) and (c), 63.8(e), (f)(4), (f)(6), 63.9(b) through (e), and (g), (h), by the dates specified. [40 C.F.R. § 63.6645(a)]
- m. The permittee shall submit an Initial Notification not later than 120 days after the source becomes subject to MACT Subpart ZZZZ. [40 C.F.R. § 63.6645(c)]
- n. The permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in 63.7(b)(1). [40 C.F.R. § 63.6645(e)]
- o. The permittee shall submit a notification of compliance status according to 63.9(h)(2)(ii). This notification shall include all performance test results, and shall be submitted by the close of business on the 60th day following the completion of the performance tests according to 63.10(d)(2). [40 C.F.R. § 63.6645(f)]
- p. The permittee shall submit each applicable report in Table 7 of Subpart ZZZZ. [40 C.F.R. § 63.6650(a)]
 - i. Each semiannual Compliance Report must contain:
 1. If there are no deviations from any emission limitations, operating limitations that apply, or any periods during which the CPMS was out of control as specified by § 63.8(c)(7), a statement that there were no deviations or out of control periods during the reporting period.
 2. If there were deviations from any emission limitations, operating limitations that apply, or any periods during which the CPMS was out of control as specified by § 63.8(c)(7), the permittee must submit the information in § 63.6650(d) and § 63.6650(e).
 3. If the permittee had a startup, shutdown, or malfunction during the reporting period, the information in § 63.10(d)(5)(i).
 - ii. Each immediate startup, shutdown, and malfunction report if actions addressing the startup, shutdown, or malfunction were inconsistent with the permittee's startup, shutdown, and malfunction plan during the reporting period must contain:
 1. Actions taken for the event;
 2. The information in § 63.10(d)(5)(i).
 - iii. Each annual report must contain:
 1. The fuel flow rate of each fuel and the heating values that were used in calculations, and
 2. The operating limits provided in the permittee's permit and any deviations from these limits; and
 3. Any problems or errors suspected with the meters.

- q. Unless the Administrator has approved a different schedule for submission of reports under 63.10(a), the permittee shall submit each report by the date in Table 7 of MACT Subpart ZZZZ and according to the following requirements: [40 C.F.R. § 63.6650(b)]
 - i. The first Compliance Report must cover the period beginning on the compliance date that is specified for the affected source in 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in 63.6595. [40 C.F.R. § 63.6650(b)(1)]
 - ii. The first Compliance Report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for the affected source in 63.6595. [40 C.F.R. § 63.6650(b)(2)]
 - iii. Each subsequent Compliance Report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. [40 C.F.R. § 63.6650(b)(3)]
 - iv. Each subsequent Compliance Report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. [40 C.F.R. § 63.6650(b)(4)]
 - v. For each stationary RICE that is subject to permitting regulations pursuant to 40 C.F.R. §70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 C.F.R. 70.6(a)(3)(iii)(A) or 40 C.F.R. 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent Compliance Reports according to the dates the permitting authority has established instead of according to the dates in paragraphs 1 through iv. [40 C.F.R. § 63.6650(b)(5)]
- r. The Compliance Report must contain the information in 63.6650(c)(1) through 63.650(c)(6). [40 C.F.R. § 63.6650(c)]
 - i. Company name and address; [40 C.F.R. § 63.6650(c)(1)]
 - ii. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and the completeness of the report; [40 C.F.R. § 63.6650(c)(2)]
 - iii. Date of the report and beginning and ending dates of the reporting period; [40 C.F.R. § 63.6650(c)(3)]
 - iv. The information in § 63.10(d)(5)(i) if there was a startup, shutdown, or malfunction during the reporting period; [40 C.F.R. § 63.6650(c)(4)]
 - v. A statement that there were no deviations from the emission or operating limitations during the reporting period, if there were no deviations; [40 C.F.R. § 63.6650(c)(5)]

- vi. A statement that there were no periods which the CPMS was out of control, if there were no out of control instances during the reporting period; [40 C.F.R. § 63.6650(c)(6)]
- s. For each deviation from an emission or operating limitations occurring for a stationary RICE where the source is using a CMS to comply with the emission and operating limitation in MACT Subpart ZZZZ, the permittee must include information in § 63.6650(c)(1) through § 63.6650(c)(6) and § 63.6650(e)(1) through § 63.650(e)(12). [40 C.F.R. § 63.650(e)]
 - i. The date and time that each malfunction started and stopped; [40 C.F.R. § 63.650(e)(1)]
 - ii. The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high level checks; [40 C.F.R. § 63.650(e)(2)]
 - iii. The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8); [40 C.F.R. § 63.650(e)(3)]
 - iv. The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period; [40 C.F.R. § 63.650(e)(4)]
 - v. A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period; [40 C.F.R. § 63.650(e)(5)]
 - vi. A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and the other unknown causes; [40 C.F.R. § 63.650(e)(6)]
 - vii. A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period; [40 C.F.R. § 63.650(e)(7)]
 - viii. An identification of each parameter and pollutant that was monitored at the stationary RICE; [40 C.F.R. § 63.650(e)(8)]
 - ix. A brief description of the stationary RICE; [40 C.F.R. § 63.650(e)(9)]
 - x. A brief description of the CMS; [40 C.F.R. § 63.650(e)(10)]
 - xi. The date of the latest CMS certification or audit; [40 C.F.R. § 63.650(e)(11)]
 - xii. A description of any changes in CMS, processes, or controls since the last reporting period. [40 C.F.R. § 63.650(e)(12)]
- t. Each affected source that obtained a Title V operating permit pursuant to 40 C.F.R. 70 or 71 must report all deviations as defined in MACT Subpart ZZZZ in the semiannual monitoring report required by 40 C.F.R. §70.6(a)(3)(iii)(A) or 40

C.F.R. 71.6(a)(3)(iii)(A). If an affected source submits a Compliance Report pursuant to Table 7 of Subpart ZZZZ along with, or as port of, the semiannual monitoring report required by 40 C.F.R. §70.6(a)(3)(iii)(A) or 40 C.F.R. §71.6(a)(3)(iii)(A), and from any emission or operating limitation in MACT Subpart ZZZZ, submission of the Compliance Report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance Report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [40 C.F.R. § 63.6650(f)]

- u. The permittee must keep the following records:
 - i. A copy of each notification and report that was submitted to comply with MACT Subpart ZZZZ, including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted according to the requirement in § 63.10(b)(2)(xiv). [40 C.F.R. § 63.6655(a)(1)]
 - ii. The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction. [40 C.F.R. § 63.6655(a)(2)]
 - iii. Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii). [40 C.F.R. § 63.6655(a)(3)]
 - iv. Records described in § 63.10(b)(2)(vi) through (xi) for each CPMS. [40 C.F.R. § 63.6655(b)(1)]
 - v. Previous, i.e. superseded, versions of the performance evaluation plan as required in § 63.8(d)(3). [40 C.F.R. § 63.6655(b)(2)]
 - vi. Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable. [40 C.F.R. § 63.6655(b)(3)]
- v. The permittee shall keep the records required in Table 6 of Subpart ZZZZ to show continuous compliance with each applicable emission or operating limitation. [40 C.F.R. § 63.6655(d)]
- w. Records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1). [40 C.F.R. § 63.6660(a)]
- x. As specified in § 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 C.F.R. § 63.6660(b)]
- y. The permittee shall keep each record readily accessible in hard copy or electronic form on-site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). The permittee can keep the records off-site for the remaining 3 years. [40 C.F.R. § 63.6660(c)]

SN-846 - Gasoline/Diesel Loading Rack

Source Description

SN-846 is gasoline and diesel loading rack. It was installed in 1980. A John Zink Carbon Adsorption Vapor Recovery Unit (VRU) was placed into operation on June 18, 1998, in order to comply with the requirements of 40 C.F.R. § 63, Subpart CC-National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The requirements of Subpart CC are outlined in the Plantwide Conditions of this permit.

Regulations

This source is not subject to 40 C.F.R. § 60, Subpart XX-Standards of Performance for Bulk Gasoline Terminals because it was constructed prior to the effective date of Subpart XX.

Specific Conditions

VRU 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with 40 C.F.R. § 63, Subpart CC and the throughput and loading requirements for this source. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Pollutant	lb/hr	tpy
846	VOC	20.2	17.1

VRU 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with Specific Condition VRU 3. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Pollutant	lb/hr	tpy
846	Ammonia	0.1	0.1

VRU 3 The total annual throughput of gasoline/ethanol blended gasoline/diesel products through this source is limited to 9,761,905 bbl per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

VRU 4 Records for the annual throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

VRU 5 The facility shall only load gasoline/ethanol blended gasoline/diesel products at this loading rack. Diesel products includes diesel and biodiesel. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

VRU 6 TOC emissions concentration shall be less than or equal to 1.1 volume percent. [Reg.19.304 and 40 C.F.R. §§ 63.427(a) and (b)]

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

VRU 7 The facility shall operate a TOC CEM system on the gasoline/diesel loading rack in order to demonstrate compliance with 40 C.F.R. § 63 Subpart CC. All CEMs shall be operated in accordance with the Department's CEM Conditions. The facility shall submit CEM data in accordance with the Department's CEMS Conditions. CEM data shall be submitted to demonstrate that the TOC concentration is less than or equal to 1.1 volume percent. [Reg.19.304 and 40 C.F.R. §§ 63.427(a) and (b)]

SN-847 - Heavy Oil Loading Racks

Source Description

SN-847 is the aggregate emissions of twelve asphalt plant loading racks. The loading racks are described in the following table.

Year Installed	Product Loaded
1987	111/219 East Asphalt Truck Rack
Pre-1950	111/219 West Asphalt Truck Rack
Pre-1950	South Asphalt Plant Truck Rack
1975	North PMA Truck Rack*
1989	North Asphalt Plant Truck Rack
Pre-1950	Pumphouse Truck Rack
1986	Lube Oil Truck Rack
Pre-1950	E & W Rail Car Rack
Pre-1950	Protective Coatings Dock
Pre-1950	Asphalt Dock
2000	South PMA Truck Rack
*The PMA Truck Rack was previously known as the Emulsion Plant Truck Rack.	

Specific Conditions

HOL 1 The permittee shall not exceed the emission rates set forth in the following table.
 Compliance with this condition will be shown by compliance with Specific Conditions HOL 2, HOL 4, and HOL 5. [§19.501 of Regulation 19 *et seq.*, and 40 C.F.R., Part 52, Subpart E]

SN	Pollutant	lb/hr	tpy
847	VOC	647.2	282.9

HOL 2 The permittee shall not exceed the emission rates set forth in the following table.
 Compliance with this condition will be shown by compliance with Specific Conditions HOL 2, HOL 4, and HOL 5. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Pollutant	lb/hr	tpy
847	Ammonia	4.7	0.9

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

- HOL 3 The facility shall load only asphalt, solvents, and lube oil-type products at these loading racks. [§19.705 of Regulation 19, A.C.A. § 8 -4-203 as referenced by §8-4-304 and §8-4-311, and 40 C.F.R. §70.6]
- HOL 4 The facility has elected to demonstrate compliance for the loading racks through a plantwide bubble. To demonstrate compliance with the plantwide bubble, the facility shall maintain a monthly inventory of the emissions from each loading rack in this section. This inventory shall be calculated by the methods and equations used in AP-42, 5th Edition, Chapter 5.2, "Transportation and Marketing of Petroleum Liquids." Records for the monthly inventory of emissions from each loading rack shall include the source name, products loaded, monthly throughput, and monthly emissions in pounds and tons. The emissions from this inventory shall be summed to determine the total amount of emissions from the combined loading racks. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]
- HOL 5 Records for the annual VOC emission rates at SN-847 shall be maintained on a twelve month rolling basis, updated monthly. The annual VOC emissions records shall be maintained on-site and submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 C.F.R., Part 52, Subpart E]

SN-849 – Stand by Diesel Crude Pump
Source Description

SN-849 is a Standby Diesel Crude Pump to be used as a backup to the primary charge pump (electrical) in the event of power failure or other related operational emergencies. This unit is rated at 325 hp and is fueled by diesel oil. This unit is fueled by low-sulfur diesel fuel provided from the low-sulfur diesel storage tank. The Standby Diesel Crude Pump was installed in 1997.

Specific Conditions

CRP 1 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operating limits of this section. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
849	Standby Diesel Crude Pump	PM ₁₀	1.4	1.4
		SO ₂	1.2	1.2
		VOC	1.6	1.5
		CO	12.2	11.6
		NO _x	20.2	19.1

CRP 2 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the operating limits of this section. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
849	Standby Diesel Crude Pump	PM	1.4	1.4
		Ammonia	0.1	0.1

CRP 3 The facility shall not exceed 20% opacity from this source. As this source operates for only a short period of time each year, a regular compliance demonstration is not necessary. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

CRP 4 The total hours of operation for this source shall be limited to 1900 hours per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

CRP 5 A meter shall be operated to record the hours of operation of SN-849. Records of the hours of operation shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

CRP 6 This source shall only be fired on fuel which contains less than 0.5 percent sulfur. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

CRP 7 The facility shall keep records demonstrating the sulfur content of the fuel used at the Standby Diesel Crude Pump (SN-849). These records may be in the form of laboratory

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

analyses performed on the fuel stored in the low-sulfur diesel storage tank which supplies fuel to this unit. If any alternative source of fuel is used to fire this unit, the alternative source and the sulfur content of the alternative fuel shall be documented. These records shall be maintained on-site and shall be made available to Department personnel upon request. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

CRP 8 The permittee shall for SN-849 operate and maintain engine and control device per manufacturer's instructions. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]

CRP 9 The permittee shall for SN-849 install a non-resettable hour meter. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]

CRP 10 The permittee must for SN-849 keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]

CRP 11 The permittee must keep records of all maintenance for SN-849. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]

CRP 12 The permittee shall for SN-849 change oil and filter and inspect hoses and belts every 500 hours or annually whichever comes first, and shall inspect air cleaner every 1000 hours or annually whichever comes first. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]

SN-851a - Wastewater Collection

Source Description

851a is the Wastewater Collection for the facility. Six tanks were installed at the facility to hold all process wastewater until it can be processed at the wastewater treatment facility. These tanks have been designated T-275, T-276, T-277, T-278, T-279, and T-280. The Wastewater Collection includes two cooling towers.

Specific Conditions

WW 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
851a	Wastewater Collection	VOC	26.1	85.9

WW 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. . [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
851a	Wastewater Collection	Ammonia	0.1	0.1

WW 3 The total throughput of wastewater at this source shall be limited to 1,064.6 MM gallons per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

WW 4 Records of the wastewater throughput shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

WW 5 The process wastewater collection system was designed, installed, and operated in compliance with the applicable provisions of 40 C.F.R. § 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. The record keeping and reporting requirements of this subpart are summarized below. [Reg.19.304 and 40 C.F.R. § 60.090]

- a. For each individual drain system or junction box subject to the requirements of § 60.692-2, the location, date, and corrective action shall be recorded for each drain when a problem is identified that could result in VOC emissions as determined in the initial and periodic visual or physical inspections.
- b. For each junction box subject to the requirements of § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by § 60.692-2(b) when a problem is identified that could result in VOC emissions.

- c. For each sewer line subject to the requirements of §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.
- d. For oil-water separators subject to § 60.692-3 the location, date, and corrective action shall be recorded for inspections required by § 60.692-3(a) when a problem is identified that could result in VOC emissions.
- e. For closed vent systems subject to § 60.692-5 and completely closed drain systems subject to § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by § 60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.
- f. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.
- g. If an emission point is not repaired in the specified amount of time, the reason for the delay as specified in § 60.692-6 shall be recorded, along with the signature of the owner or operator whose decision it was that repair could not be effected without a refinery or process shutdown, and the date that the repair or corrective action was successfully completed.
- h. A copy of the design specifications for all equipment used to comply with the provisions of Subpart QQQ shall be kept for the life of the source in a readily accessible location. These records shall include the following information:
 - i. Detailed schematics and piping and instrumentation diagrams.
 - ii. The dates and descriptions of any changes in the design specifications.
- i. Additional information shall be maintained for specific equipment as indicated in 40 C.F.R. § 60.697 (f)(3)(i)-(x).
- j. If the permittee elects to install a tightly sealed cap or plug over a drain that is out of active service, the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which indicate the location of such drains.
- k. For stormwater sewer systems subject to the exclusion in § 60.692-1(d)(1), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.
- l. For ancillary equipment subject to the exclusion in § 60.692-1(d)(2), the permittee shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.
- m. For non-contact cooling water systems subject to the exclusion in § 60.692-1(d)(3), the permittee shall keep for the life of the facility in a readily accessible

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

- n. The permittee shall submit to the Department within 60 days after initial startup of the “new” wastewater collection system a certification that the equipment necessary to comply with the standards of Subpart QQQ has been installed and that all necessary initial inspections have been conducted in accordance with these standards.
- o. After the initial certification, the permittee shall submit semiannually a certification that all of the required inspections have been carried out in accordance with the standards of Subpart QQQ.

Cooling Towers
SN-853 - Cooling Towers
SN-853a - #5 Cooling Tower
SN-853b #7 Cooling Tower
SN-859 – #8 Cooling Tower

Source Description

The #3, 5, 6, 7, and 17 Sulfur Plant cooling towers are used to transfer waste heat from the cooling water to the atmosphere. They were installed in the 1970's. The #1 Cooling Tower was removed from service in 2003 and replaced with the new #8 cooling tower, which has been designated as SN-859.

The #5 cooling tower was modified in 2005 to install drift eliminators for PM₁₀ control. SN-853a was added to account for the particulate emissions from the modified #5 tower. Cooling Tower #7 is SN-853a and Cooling Tower #8 is SN-859.

Specific Conditions

CT 1 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
853	Cooling Towers	PM ₁₀	15.9	63.3
853a				
853b		VOC	15.3	67.4
859				
* SN-853 limits include emissions from all six cooling towers (3, 5, 6, 7, 8, and 17)				

CT 2 The permittee shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by compliance with the throughput limits of this section. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
853	Cooling Towers	PM	15.9	63.3
853a				
853b				
859				
* SN-853 limits include emissions from all six cooling towers (3, 5, 6, 7, 8, and 17)				

CT 3 The total amount of water circulated at the #3, 5, 6, 7, 8, and 17 Sulfur Plant cooling towers shall be limited to 51.5 billion gallons per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

- CT 4 The total amount of water circulated at the #5 cooling tower shall be limited to 13.26 billion gallons per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- CT 5 The total amount of water circulated at the #8 Cooling Tower (SN-859) shall be limited to 10.5 billion gallons per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- CT 6 The total amount of water circulated at the #7 Cooling Tower (SN-853b) shall be limited to 6.4 billion gallons per consecutive twelve month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- CT 7 Records of the water circulated shall be maintained on a twelve month rolling basis, updated monthly. Such records shall be maintained on site and submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

SN-854 - Fugitive Equipment Leaks
SN-858f – Tier 2 Fugitives and Tanks VOC Bubble

SN-869 - Tank 536 Truck Loading Rack

Crude Oil Unloading

Source Description

The fugitive emissions not quantified with the other sources are included in this grouping. This bubble also includes emissions listed in the Tier II Fugitive Bubble (SN-858f).

The Tank 536 Truck Loading Rack, SN-869, loads intermediate products in to transport vehicles. The loading rack emissions are routed to a fuel gas system or back into a process as specified in 40 CFR § 63 Subpart SS. The only emissions are from equipment leaks accounted for in other sources.

The Crude Oil Unloading is subject to 40 C.F.R. § 63 Subpart TT – National Emission Standards for Equipment Leaks – Control Level 1 as referenced by Subpart EEEE. The only emissions are from equipment leaks accounted for in other sources.

Regulations

All fugitive equipment leak sources associated with the Tier II project are subject to 40 C.F.R. § 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC from Petroleum Refineries.

All sources of VOC equipment leaks associated with the Tier II project are subject to 40 C.F.R. § 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry as referenced by Subpart GGG.

Portions of the facility associated with crude unloading are subject to 40 C.F.R. § 63 Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

Specific Conditions

LEAK 1 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and the conditions of 40 C.F.R. §§ 60, Subparts GGG and VV, as referenced by Subpart GGG and 40 C.F.R. § 63, Subpart CC, for those components subject to the requirements of Subparts GGG, VV or CC (respectively). [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN #	Source Description	Pollutant	lb/hr	tpy
854	Fugitive Equipment Leaks	VOC	680.1	2979.0
858f	Tier II Fugitive Equipment Leaks	VOC	*	41.3
*Short term emissions from Tier II fugitives are subject to the short- term limit for all facility fugitives found under SN-854.				

LEAK 2 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by an annual emissions inventory and the conditions of 40 C.F.R. §§ 60 Subparts GGG and VV, as referenced by Subpart GGG and 40 C.F.R. § 63, Subpart CC, for those components subject to the requirements of Subparts GGG, VV or CC (respectively). [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN #	Source Description	Pollutant	lb/hr	tpy
854	Fugitive Equipment Leaks	Ammonia	1.0	4.4
		H ₂ S	80.2	351.3

LEAK 3 The facility shall conduct an annual emission inventory to demonstrate compliance with the emission limits of Specific Condition LEAK 1. This inventory shall be calculated by the methods and equations used in AP-42, Chapter 5.1 (5th Edition or later version) or Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 (November 1995 or later version), or other ADEQ-approved method. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

LEAK 4 Records for the emission inventory required in Specific Condition LEAK 2 shall be maintained on an annual basis. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), beginning in year 2003, and shall be submitted in accordance with General Provision 7 no later than August 1 of each year. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

LEAK 5 The equipment, including each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service in the #4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant, the Polymer Asphalt Letdown Facility, and the equipment associated with the Tier II clean fuels project, are affected facilities under the terms of 40 C.F.R. § 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. For the purposes of recordkeeping and reporting only, compressors are also considered affected facilities. The facility is subject to the Subpart GGG requirements, which are summarized below. [Reg.19.304 and 40 C.F.R. §§ 60.590(a)(1) and (3)]

- a. The facility shall comply with the standards for specific equipment found in §§ 60.482-1 to 60.482-10 of 40 C.F.R. § 60, Subpart VV. [§ 60.592(a)]

- b. An owner or operator may elect to comply with the alternative standards for valves in §§ 60.483-1 and 60.483-2. [§ 60.592(b)]
- c. An owner or operator may apply to the Administrator for a permit modification for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484. [§ 60.592(c)]
- d. Each owner or operator subject to the provisions of this subpart shall comply with the testing provisions of § 60.485 except as provided in § 60.593. [§ 60.592(d)]
- e. Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping and reporting provisions of §§ 60.486 and 60.487. [§ 60.592(e)]
- f. Each owner or operator subject to the provisions of MACT Subpart GGG may comply with the allowable exceptions to the provisions of subpart VV. [§ 60.593(a)]

LEAK 6 This facility is subject to 40 C.F.R. § 60 Subpart VV-*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry* as referenced by Subpart GGG. The facility is subject to the requirements of Subpart VV which are summarized below. [Reg.19.304 and 40 C.F.R. §§ 60.590 and 60.592]

- a. The facility shall demonstrate compliance with the requirements of §§ 60.482-1 to 60.482-10 for all equipment within 180 days of initial startup. [§ 60.482-1(a)]
- b. Compliance with §§ 60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485. [§ 60.482-1(b)]
- c. The facility may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484. (Note: This will require a permit modification.) [§ 60.482-1(c)(1)]
- d. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, or 60.482-10, the facility shall comply with the requirements of that determination. (Note: This will require a permit modification.) [§ 60.482-1(c)(2)]
- e. The compressors in hydrogen service are not subject to MACT Subpart GGG as per the exemption of § 60.593(b)(1). [§ 60.482-3(a)]
- f. The permittee shall for each pressure relief devices in gas/vapor service comply with §60.482-4. [§ 60.482-4]
- g. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c). [§ 60.482-6(a)(1)]

- h. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. [§ 60.482-6(a)(2)]
- i. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. [§ 60.482-6(b)]
- j. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times. [§ 60.482-6(c)]
- k. The facility shall comply with the requirements for valves in gas/vapor service or in light liquid service. [§ 60.482-7]
- l. The facility shall comply with the requirements for closed vent systems and control devices. [§ 60.482-10]
- m. The facility has elected to comply with the alternative work practice specified in paragraphs (b)(3) of 60.483. [§ 60.483-2]
- n. The facility has notified the Administrator before implementing these alternative work practices, as specified in § 60.487(d). [§ 60.483-2(2)]
- o. The facility has initially complied with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7. [§ 60.483-2(b)(1)]
- p. After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. [§ 60.483-2(b)(3)]
- q. If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use 60.483. [§ 60.483-2(b)(4)]
- r. In conducting the performance tests required in § 60.8, the facility shall use as reference methods and procedures the test methods in Appendix A of this 40 C.F.R. § 60 Subpart A or other methods and procedures as specified in 60.485, except as provided in § 60.8(b). [§ 60.485(a)]
- s. The facility shall determine compliance with the standards in §§ 60.482 and 60.483 as follows: [§ 60.485(b)]
 - i. Method 21 (or other approved method) shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 (or other approved method). The following calibration gases shall be used:
 - 1. Zero air (less than 10 ppm of hydrocarbon in air); and

2. A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.
- t. The facility shall determine compliance with the no detectable emission standards in §§ 60.482-2(e), and 60.482-3(i) as follows: [§ 60.485(c)]
 - i. The requirements of paragraph (b) shall apply.
 - ii. Method 21 (or other approved method) shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.
 - iii. Samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare. [§ 60.485(f)]
 - u. The facility shall comply with the recordkeeping requirements of § 60.486. [§ 60.486(a)(1)]
 - v. An owner or operator of more than one affected facility subject to the provisions of MACT Subpart GGG may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility. [§ 60.486(a)(2)]
 - w. When each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply: [§ 60.486(b)]
 - i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
 - ii. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7(c) and no leak has been detected during those 2 months.
 - iii. The identification on equipment except on a valve, may be removed after it has been repaired.
 - x. The provisions of § 60.7 (b) and (d) do not apply to affected facilities subject to MACT Subpart GGG. [§ 60.486(k)]
 - y. The facility shall submit semiannual reports to the Administrator beginning six months after the initial start up date. [§ 60.487(a)]
 - z. The initial semiannual report to the Administrator shall include the following information: [§ 60.487(b)]
 - i. Process unit identification.
 1. Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

2. Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).
 3. Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3(i) and those compressors complying with § 60.482-3(h).
- aa. All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486: [§ 60.487(c)]
- i. Process unit identification.
 - ii. For each month during the semiannual reporting period,
 1. Number of valves for which leaks were detected as described in § 60.482(7)(b) or § 60.483-2,
 2. Number of valves for which leaks were not repaired as required in § 60.482-7(d)(1),
 3. Number of pumps for which leaks were detected as described in § 60.482-2(b) and (d)(6)(i),
 4. Number of pumps for which leaks were not repaired as required in § 60.482-2(c)(1) and (d)(6)(ii),
 5. Number of compressors for which leaks were detected as described in § 60.482-3(f),
 6. Number of compressors for which leaks were not repaired as required in § 60.482-3(g)(1), and
 7. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
 - iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - iv. Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.
- bb. The facility has elected to comply with the provisions of § 60.483-2 and has notified the Administrator of the alternative standard selected 90 days before implementing the provision. If the facility decides to comply with the provisions of § 60.483-1, the facility shall notify the Administrator 90 days in advance before implementing the provisions. [§ 60.487(d)]
- cc. The facility shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of MACT Subpart GGG except that the facility

must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests. [§ 60.487(e)]

LEAK 7 In order to demonstrate compliance with Subparts GGG and VV the facility shall maintain a log of the following. [[Reg.19.304 and 40 C.F.R. §§ 60, Subparts GGG and VV]

- a. Compliance with testing provisions as required by § 60.592(d).
- b. Any exemptions for compressors considered to be in hydrogen service.
- c. Any exemptions for equipment that is in vacuum service as provided by § 60.482-1(d).
- d. Monthly monitoring results of § 60.482-2(a)(1).
- e. Weekly visual inspection checks of liquids dripping of § 60.482-2(a)(2).
- f. Record of instrument reading of § 60.482-2(b)(1).
- g. Record of leaks from pump seal in § 60.482-2(b)(2).
- h. Attempts to repair leak within 15 days as provided by § 60.482-2(c)(1).
- i. Attempts to repair leak within 5 days as provided by § 60.482-2(c)(2).
- j. Records of exemption for each pump equipped with a dual mechanical seal system as provided by § 60.482-2(d).
- k. Records of exemption for any pump designated for no detectable emission as provided by § 60.482-2(e).
- l. Records of exemption for any pump equipped with a closed vent system as provided by § 60.482-2(f).
- m. Records that each sampling connection system is equipped with a closed purge system or closed vent system in § 60.482-5(a) and (b) or qualifies for the exemptions.
- n. All in-situ sampling systems that are exempt in § 60.482-5(c).
- o. Record of monitoring of potential leaks within 5 days as required by § 60.482-8(a).
- p. Record of leaks detected in § 60.482-8(b).
- q. Attempts to repair leak within 15 days as provided by § 60.482-8(c)(1).
- r. Attempts to repair leak within 5 days as provided by § 60.482-8(c)(2).
- s. Record of delay of repair of equipment as allowed in § 60.482-9(a) or (b).
- t. Record of delay of repair of equipment as allowed in § 60.482-9(c).
- u. Record of delay of repair of equipment as allowed in § 60.482-9(d).
- v. Delays of repair beyond a process unit shutdown as allowed in § 60.482-9(e).
- w. Record of the percent of valves leaking as required in § 60.483-2(5) and (6).

- x. Records of the tests and results of § 60.485(d).
- y. Results of § 60.485.
- z. Records of § 60.485(g).
- aa. Information required by § 60.486(c) for leaks.
- bb. Information required by § 60.486(d) for the design requirements for closed vent system/control device.
- cc. Information required by § 60.486(e) for the equipment.
- dd. Information required by § 60.486(f) for the valves.
- ee. Information required by § 60.486(g) for the valves.
- ff. Information required by § 60.486(h).
- gg. Requirements to show that equipment is not in VOC service as provided by § 60.486(j).

LEAK 8 Under the terms of 40 C.F.R. § 63 Subpart EEEE- National Emission Standard for Hazardous Air Pollutants: Organic Liquid Distribution, the Tank 536 Truck Loading Rack (SN-869) is an affected facility. The Tank 536 Truck Loading Rack, associated leak components, and transport vehicles must meet the following control requirements since the rack will be permitted to load over 800,000 gallons of organic liquid per year.
[Reg.19.304 and 40 C.F.R. § 63.2346]

- a. **Transfer racks.** For each transfer rack that is part of the collection of transfer racks that meets the total actual annual facility-level organic liquid loading volume criterion for control in Table 2 to Subpart EEEE, items 7 through 10, the permittee must comply with paragraph (b)(1), (b)(2), or (b)(3) of § 63.2346 for each arm in the transfer rack loading an organic liquid whose organic HAP content meets the organic HAP criterion for control in Table 2 to Subpart EEEE, items 7 through 10. For existing affected sources, the permittee must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) of § 63.2346 during the loading of organic liquids into transport vehicles. For new affected sources, the permittee must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) and (ii) of § 63.2346 during the loading of organic liquids into transport vehicles and containers. Route emissions to fuel gas systems or back into a process as specified in 40 C.F.R. § 63, subpart SS.
- b. **Equipment leak components.** For each pump, valve, and sampling connection that operates in organic liquids service for at least 300 hours per year, the permittee must comply with the applicable requirements under 40 C.F.R. § 63, subpart TT (control level 1), subpart UU (control level 2), or subpart H. Pumps, valves, and sampling connectors that are insulated to provide protection against persistent sub-freezing temperatures are subject to the "difficult to monitor" provisions in the applicable subpart selected by the owner or operator. This paragraph only applies if the affected source has at least one storage tank or transfer rack that meets the applicability criteria for control in Table 2 to Subpart EEEE.

- c. **Transport vehicles.** For each transport vehicle equipped with vapor collection equipment that is loaded at a transfer rack that is subject to control based on the criteria specified in Table 2 to this Subpart EEEE, items 7 through 10, you must comply with paragraph (d)(J) of § 63.2346. For each transport vehicle without vapor collection equipment that is loaded at a transfer rack that is subject to control based on the criteria specified in Table 2 to Subpart EEEE, items 7 through 10, the permittee must comply with paragraph (d)(2) of § 63.2346.
 - i. Follow the steps in 40 C.F.R. 60.502(e) to ensure that organic liquids are loaded only into vapor-tight transport vehicles and comply with the provisions in 40 C.F.R. 60.502(f) through (i), except substitute the term "transport vehicle" at each occurrence of the term "tank truck" or "gasoline tank truck" in those paragraphs.
 - ii. Ensure that organic liquids are loaded only into transport vehicles that have a current certification in accordance with the U.S. Department of Transportation (DOT) pressure test requirements in 49 C.F.R. §180 for cargo tanks or 49 C.F.R. 173.31 for tank cars.
- d. **Reporting.** The permittee must submit each report in subpart SS of this part, Table 11 to this subpart, Table 12 to Subpart EEEE, and in paragraphs (c) through (e) of 63.2386 that apply to the facility.
 - i. 63.2386(b). Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), the permittee must submit each report according to Table 11 to this subpart and by the dates shown in paragraphs (b)(1) through (3) of 63.2386, by the dates shown in subpart SS of this part, and by the dates shown in Table 12 to Subpart EEEE, whichever are applicable.
 - 1. The first Compliance report must cover the period beginning on the compliance date that is specified for the affected source in § 63.2342 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the affected source in § 63.2342.
 - 2. The first Compliance report must be postmarked no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for the affected source in § 63.2342.

3. Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
 4. Each subsequent Compliance report must be postmarked no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
 5. For each affected source that is subject to permitting regulations pursuant to 40 C.F.R. §70 or 40 C.F.R. §71, if the permitting authority has established dates for submitting semiannual reports pursuant to 40 C.F.R. 70.6(a)(3)(iii)(A) or 40 C.F.R. 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) and (2) of 63.2386.
- ii. 63.2386(c). The first Compliance report must contain the information specified in paragraphs (c)(1) through (10) of 63.2386.
1. Company name and address.
 2. Statement by a responsible official, including the official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
 3. Date of report and beginning and ending dates of the reporting period.
 4. Any changes to the information listed in § 63.2382(d)(2) that have occurred since the submittal of the Notification of Compliance Status.
 5. If the permittee had a SSM during the reporting period and the permittee took actions consistent with the SSM plan, the Compliance report must include the information described in § 63.10(d)(5)(i).
 6. If there are no deviations from any emission limitation or operating limit that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations, operating limits, or work practice standards during the reporting period.

7. If there were no periods during which the CMS was out of control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out of control during the reporting period .
8. For closed vent systems and control devices used to control emissions, the information specified in paragraphs (c)(8)(i) and (ii) of 63.2386 for those planned routine maintenance activities that would require the control device to not meet the applicable emission limit.
 - a. A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description must include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.
 - b. A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description must include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the applicable emission limit due to planned routine maintenance.
9. A listing of all transport vehicles into which organic liquids were loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, during the previous 6 months for which vapor tightness documentation as required in § 63.2390(c) was not on file at the facility.
10. A listing of all transfer racks (except those racks at which only unloading of organic liquids occurs) and of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that are part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of Subpart EEEE.
11. If the information specified in paragraph (c)(10)(i) of 63.2386 has already been submitted with the Notification of Compliance Status, the information specified in paragraphs (d)(3) and (4) of 63.2386, as applicable, shall be submitted instead.

- iii. 63.2386(d). Subsequent Compliance reports must contain the information in paragraphs (c)(1) through (9) of 63.2386 and, where applicable, the information in paragraphs (d)(1) through (4) of 63.2386.
1. 63.2386(d)(1). For each deviation from an emission limitation occurring at an affected source where you are using a CMS to comply with an emission limitation in this subpart, you must include in the Compliance report the applicable information in paragraphs (d)(1)(i) through (xii) of 63.2386. This includes periods of SSM.
 2. 63.2386(d)(2)(i). For each storage tank and transfer rack subject to control requirements, include periods of planned routine maintenance during which the control device did not comply with the applicable emission limits in table 2 to Subpart EEEE.
 3. 63.2386(d)(2)(ii). For each storage tank controlled with a floating roof, include a copy of the inspection record (required in § 63.1065(b)) when inspection failures occur.
 4. 63.2386(d)(2)(iii). If the permittee elects to use an extension for a floating roof inspection in accordance with § 63.1063(c)(2)(iv)(B) or (e)(2), include the documentation required by those paragraphs.
 5. 63.2386(d)(3)(i). A listing of any storage tank that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 1 through 6, since the filing of the last Compliance report.
 6. 63.2386(d)(3)(ii). A listing of any transfer rack that became subject to controls based on the criteria for control specified in table 2 to Subpart EEEE, items 7 through 10, since the filing of the last Compliance report.
 7. 63.2386(d)(4)(i). A listing of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of Subpart EEEE, since the last Compliance report.
 8. 63.2386(d)(4)(ii). A listing of all transfer racks (except those racks at which only the unloading of organic liquids occurs) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of Subpart EEEE, since the last Compliance report.

- iv. 63.2386(e). Each affected source that has obtained a title V operating permit pursuant to 40 C.F.R. §70 or 40 C.F.R. §71 must report all deviations as defined in Subpart EEEE in the semiannual monitoring report required by 40 C.F.R. 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 11 to Subpart EEEE along with, or as part of, the semiannual monitoring report required by 40 C.F.R. 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission limitation in Subpart EEEE, we will consider submission of the Compliance report as satisfying any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report will not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the applicable title V permitting authority.
- e. **Recordkeeping.** For each emission source identified in § 63.2338 that does not require control under Subpart EEEE, the permittee must keep all records identified in § 63.2343.
- i. 63.2390(b). For each emission source identified in § 63.2338 that does require control under Subpart EEEE:
 - 1. The permittee must keep all records identified in subpart SS of this part and in table 12 to Subpart EEEE that are applicable, including records related to notifications and reports, SSM, performance tests, CMS, and performance evaluation plans; and
 - 2. The permittee must keep the records required to show continuous compliance, as required in subpart SS of this part and in tables 8 through 10 to Subpart EEEE, with each emission limitation, operating limit, and work practice standard that applies.
- ii. 63.2390(c). for each transport vehicle into which organic liquids are loaded at a transfer rack that is subject to control based on the criteria specified in table 2 to Subpart EEEE, items 7 through 10, the permittee must keep the applicable records in paragraphs (c)(1) and (2) of 63.2390 or alternatively the verification records in paragraph (c)(3) of 63.2390.
 - 1. For transport vehicles equipped with vapor collection equipment, the documentation described in 40 C.F.R. 60.505(b), except that the test title is: Transport Vehicle Pressure Test-EPA Reference Method 27.
 - 2. For transport vehicles without vapor collection equipment, current certification in accordance with the U.S. DOT pressure test

requirements in 49 C.F.R. §180 for cargo tanks or 49 C.F.R. 173.31 for tank cars.

3. In lieu of keeping the records specified in paragraph (c)(1) or (2) of 63.2390, as applicable, the owner or operator shall record that the verification of U.S. DOT tank certification or Method 27 of appendix A to 40 C.F.R. § 60 testing, required in table 5 to Subpart EEEE, item 2, has been performed. Various methods for the record of verification can be used, such as: A check-off on a log sheet, a list of U.S. DOT serial numbers or Method 27 data, or a position description for gate security showing that the security guard will not allow any trucks on site that do not have the appropriate documentation.
- iii. 63.2390(d). The permittee must keep records of the total actual annual facility level organic liquid loading volume as defined in § 63.2406 through transfer racks to document the applicability, or lack thereof, of the emission limitations in table 2 to Subpart EEEE, items 7 through 10.
- iv. 63.2390(e). An owner or operator who elects to comply with § 63.2346(a)(4) shall keep the records specified in paragraphs (e)(1) through (3) of 63.2390.
 1. A record of the U.S. DOT certification required by § 63.2346(a)(4)(ii).
 2. A record of the pressure relief vent setting specified in § 63.2346(a)(4)(v).
 3. If complying with § 63.2346(a)(4)(vi)(B), keep the records specified in paragraphs (e)(3)(i) and (ii) of 63.2390.
 - a. A record of the equipment to be used and the procedures to be followed when reloading the cargo tank or tank car and displacing vapors to the storage tank from which the liquid originates.
 - b. A record of each time the vapor balancing system is used to comply with § 63.2346(a)(4)(vi)(B).

LEAK 9 The equipment, including each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at the Crude Oil Unloading Rack, are affected facilities under the terms of 40 CFR Part 63 Subpart TT as referenced by 40 CFR Part 63 Subpart EEEE. The facility is subject to the Subpart TT requirements, which are summarized below. [§19.304 of Regulation 19, and 40 CFR §63.1000]

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

1. The facility shall comply with the standards for specific equipment found in §§63.1002 to 63.1015 of 40 C.F.R. 63, Subpart TT.
2. An owner or operator may elect to comply with the alternative standards for valves in §§63.1016.
3. Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping and reporting provisions of §§63.1017 and 63.1018.

SN-856 - Facility Tanks – Plantwide Bubble
856a - Asphalt Tanks
SN-858t – Tier 2 Fugitives and Tanks VOC Bubble

Source Description

In order to demonstrate compliance with the emission limits for the tanks, the facility has decided to operate under a Plantwide Applicability Limit (PAL). The PAL is meant to allow the facility flexibility in operation and production while at the same time limiting the aggregate emissions from the tanks. The following is a summary of all tanks (including Tier II tanks, SN-858t) included in the PAL and the applicable regulations.

For simplicity, all of the tanks are described in the following table.

Tank Type Key

FCR	Fixed Cone Roof
FDR	Fixed Dome Roof
FFR	Fixed Flat Roof
EFR	External Floating Roof
IFR	Internal Floating Roof
OR	Open Roof Tank
HOR	Horizontal Tank

Tank Description

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-4	FCR	1953	4,890	---
T-7	EFR	1999	20,000	Kb
T-11	FCR	1959	4,930	---
T-14	FCR	1942	2,997	---
T-19	FCR	2002	2,000	Kb
T-23	FCR	1953	1,930	---
T-24	FCR	1999	3,059	UU see notes ⁱⁱⁱ
T-36	IFR	1953	4,890	---
T-39	FCR	1958	4,890	---
T-40	FCR	1940	3,672	---
T-41	FCR	2005	3,672	UU
T-42	HOR	2007	1,019	---
T-043	FCR	2014	762	
T-51	FCR	1940	11,748	---
T-54*	FDR	1922	15,090	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-59	FCR	2002	8,200	Kb
T-61	EFR	1949	20,160	---
T-62	EFR	1949	20,140	---
T-63	FCR	1957	8,602	---
T-64	IFR	1957	10,120	---
T-65	EFR	1954	10,120	---
T-78	FCR	1999	5,000	UU
T-82	FCR	2004	20,081	---
T-84	FCR	1953	10,120	---
T-85	IFR	1954	10,120	---
T-88	EFR	1987	20,120	Kb
T-89	EFR	1948	20,120	---
T-98	FCR	1940	990	---
T-101	FCR	1922	54,990	---
T-102	FCR	1922	55,236	---
T-103	EFR	1995	50,000	Kb
T-104	FCR	1923	55,500	---
T-105	FCR	1923	64,310	---
T-107	FCR	1923	55,140	---
T-108*	IFR	1982	55,447	Ka
T-109*	IFR	1982	55,367	Ka
T-110	FCR	1928	55,628	---
T-112*	FCR	2005	151,065	UU see notes ⁱⁱⁱ
T-113*	EFR	2003	50,000	Kb
T-114	FCR	1923	54,720	---
T-115	FCR	1923	54,601	---
T-118	FCR	1944	54,813	---
T-119	FCR	2013	30,000	Kb
T-120	IFR	1949	80,419	---
T-121*	FCR	1949	80,440	---
T-122*	FCR	1953	80,440	---
T-123	EFR	1949	80,377	---
T-124	EFR	1959	54,432	---
T-125	EFR	1953	55,960	---
T-126	EFR	1953	55,960	---
T-128	EFR	1959	81,216	---
T-142	FCR	1982	2,000	see notes ^{iv}
T-143	FCR	1982	2,000	see notes ^{iv}
T-162	FCR	1951	2,050	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-167	FCR	1940	1,120	---
T-168	FCR	1940	1,331	---
T-175	FCR	1940	5,128	---
T-176	FCR	1940	5,128	---
T-180	FCR	1959	300	---
T-188	FCR	1981	5,060	Ka
T-191	FCR	2009	144,607	
T-192	FCR	2008	137,068	
T-199	FCR	1957	1,893	---
T-201	HOR	2004	500	---
T-217	HOR	1964	52	---
T-219	FCR	1967	56,000	---
T-241	FCR	1953	2,775	---
T-242	FCR	1953	2,688	---
T-243	FCR	1953	3,279	---
T-245	IFR	1953	3,132	---
T-246	IFR	1953	3,107	---
T-247*	IFR	2003	5,130	Kb
T-262	FCR	1938	5,061	---
T-263	FCR	1938	5,061	---
T-264	FCR	1938	5,061	---
T-265	FCR	1938	5,061	---
T-270	FCR	1941	9,384	---
T-271	FCR	1941	9,240	---
T-272	FCR	1986	1,000	see notes ⁱⁱⁱ
T-273	FCR	1986	1,000	see notes ⁱⁱⁱ
T-274	FCR	1986	1,000	see notes ⁱⁱⁱ
T-306	FCR	1952	133	---
T-330	FCR	1950	286	---
T-348	FCR	1968	5,275	---
T-349	FCR	1968	5,279	---
T-350	FCR	1954	1,382	---
T-351	FCR	1954	1,382	---
T-352	FCR	1954	1,382	---
T-353	FCR	1954	1,382	---
T-355	FCR	1959	1,006	---
T-356	FCR	1961	285	---
T-360	IFR	1957	15,120	---
T-361	IFR	1957	15,120	---
T-368	FCR	1966	10,120	---

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-371	IFR	1959	10,120	---
T-372	IFR	2003	10,120	Kb
T-382	FCR	2000	5,000	UU see notes ⁱⁱⁱ
T-383	FCR	2000	5,000	UU see notes ⁱⁱⁱ
T-384	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-385	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-386	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-387	FCR	1999	3,060	UU see notes ⁱⁱⁱ
T-394	FCR	1992	286	see notes ^v
T-532	IFR	1981	32,784	Ka
T-538	FCR	1989	24	see notes ^{vi}
T-539	FCR	1989	24	see notes ^{vi}
T-540	HOR	1987	242	---
T-544	FCR	1991	5,250	see notes ⁱⁱⁱ
T-548	FCR	1993	100,000	see notes ⁱⁱⁱ
T-549	FCR	1994	143	see notes ^{vi}
T-551	HOR	1994	24	see notes ^{vi}
T-552	HOR	1996	242	see notes ^{vi}
T-553	FCR	1999	1,500	see notes ⁱⁱⁱ
T-570	EFR	1959	125,000	---
T-600	HOR	1994	48	see notes ^{vi}
T-601	HOR	1994	24	see notes ^{vi}
T-602	HOR	1994	24	see notes ^{vi}
T-603	HOR	1995	24	see notes ^{vi}
T-605	HOR	1996	13	see notes ^{vi}
T-606	HOR	1996	13	see notes ^{vi}
T-607	HOR	1990	36	see notes ^{vi}
T-608	HOR	1987	190	see notes ^{vi}
T-609	HOR	1995	143	see notes ^{vi}
T-610	FCR	1980	8	see notes ⁱⁱ
T-611	FCR	1995	190	see notes ^{vi}
T-612	FCR	1995	71	see notes ^{vi}
T-613	HOR	2000	75	see notes ^{vi}

SN	Tank Design	Year	Storage Capacity (barrels)	NSPS Regulation
T-616	FCR	2000	48	see notes ^{vi}
T-618	FCR	2001	24	see notes ^{vi}
T-619	HOR	2001	48	see notes ^{vi}
T-620	HOR	2001	24	see notes ^{vi}
T-621	HOR	2001	13	see notes ^{vi}
T-622	HOR	2001	24	see notes ^{vi}
T-700	FCR	2012	14,000	---
T-701t	FCR	2012	19	---
T-702t	FR	2012	19	---
T-703t	FR	2012	19	---
T-New	FCR	2007	150,000	UU
T-998	IFR	2008	80,419	Kb
*Denotes a tank associated with the Tier II project.				

NSPS Regulation Notes

- i. Reserved
- ii. Pursuant to 40 C.F.R. § 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, Tank T-610 is not an affected source because it is smaller than 40,000 gallons.
- iii. Pursuant to 40 C.F.R. § 60, Subpart Kb- *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tanks T-24, T-113, T-272 through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempt from the control requirements of Subpart Kb by § 60.112b(a) because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (0.75 psia). (
- iv. Pursuant to 40 C.F.R. § 60, Subpart Ka-*Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984*, T-142, T-143, T-188 and T-432 are not affected facilities because they do not store volatile organic liquids with vapor pressure greater than 1.5 psia (10.3 kPa).
- v. Pursuant to 40 C.F.R. § 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank T-324 is not an affected source under § 60.110(a) because it does not contain a VOL.
- vi. Pursuant to 40 C.F.R. § 60, Subpart Kb-*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, tank's T-538, T-539, T-549 to T-552, T-600 to T-609, T-611, T-612, T-613, T-616, T-618, T-619,

T-620, T-621, and T-622 are not affected sources because they are smaller than 75 m³.

- vii. All other tanks, which are not listed above except tanks T-7, T-19, T-59, T-88, T-103, T-108, T-109, T-113, T-188, T-247, T-372, and T-532, are not subject to 40 C.F.R. § 60, Subparts K, Ka, or Kb. The NSPS requirements for tanks these tanks are outlined in the Specific Conditions.
- viii. All tanks have been classified as a Group I or Group II storage vessel in accordance with the provisions of 40 C.F.R. § 63, Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*. Subpart CC is outlined in the Plantwide Conditions of this permit.

Specific Conditions

TANK 1 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by completing an annual emissions inventory, refinery crude feed rate limits, and maximum vapor pressure restrictions. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Pollutant	lb/hr	tpy
856	PM ₁₀	16.4	7.3
	VOC	5,728.2	2,563.5
	CO	123.6	55.3
858t	VOC	*	322.5
856a	VOC	*	10.0
* Short term emissions from Tier II tanks (SN-858t) and asphalt tanks (SN-856a) are subject to the short-term limit for all facility tanks found under SN-856.			
Tanks in the SN-856a group are: T-170, T-199, T-180, T-190, T-310, T-311, T-312, T-313, T-314, T-315, T-319, T-320, T-321, T-322, T-323, T-325, T-326, T-327, T-328, T-331, T-332, T-333, T-335, T-336, T-337, T-338, T-340, T-349, T-350, T-324, T-351, T-72, T-353, T-145, T-339, T-73, T-352, T-74, T-201, T-162, T-173			

TANK 2 The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by completing an annual emissions inventory, refinery crude feed rate limits, and maximum vapor pressure restrictions. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Pollutant	lb/hr	tpy
856	PM	16.4	7.3
	Ammonia	3.3	14.2

Lion Oil Company
 Permit #: 0868-AOP-R10
 AFIN: 70-00016

TANK 3 The facility shall store only products with calendar month average true vapor pressure equal to or less than the vapor pressure listed for each tank in the following table. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

SN	Maximum Vapor Pressure (PSI)	SN	Maximum Vapor Pressure (PSI)	SN	Maximum Vapor Pressure (PSI)
T-4	14.7 ^D	T-85	11.1 ^{FR}	T-126	11.1 ^{FR}
T-7	11.1 ^{FR}	T-88	11.1 ^{FR}	T-128	11.1 ^{FR}
T-11	14.7 ^D	T-89	11.1 ^{FR}	T-142	1.5 ^{NC}
T-14	14.7 ^D	T-98	14.7 ^D	T-143	1.5 ^{NC}
T-19	0.75 ^{NC}	T-101	14.7 ^D	T-162	14.7 ^D
T-23	14.7 ^D	T-102	14.7 ^D	T-167	14.7 ^D
T-24	0.75 ^{NC}	T-103	11.1 ^{FR}	T-168	14.7 ^D
T-36	11.1 ^{FR}	T-104	14.7 ^D	T-175	14.7 ^D
T-39	14.7 ^D	T-105	14.7 ^D	T-176	14.7 ^D
T-40	14.7 ^D	T-107	14.7 ^D	T-180	14.7 ^D
T-41	14.7 ^C	T-108	1.5 ^{NC}	T-188	1.5 ^{NC}
T-42	14.7 ^D	T-109	1.5 ^{NC}	T-191	14.7 ^D
T-043	0.33	T-110	14.7 ^D	T-192	14.7 ^D
T-51	14.7 ^D	T-112	0.75 ^{NC}	T-199	14.7 ^D
T-54	14.7 ^D	T-113	11.1 ^{FR}	T-201	14.7 ^C
T-59	0.75 ^{NC}	T-114	14.7 ^D	T-217	14.7 ^D
T-61	11.1 ^{FR}	T-115	14.7 ^D	T-219	14.7 ^D
T-62	11.1 ^{FR}	T-118	14.7 ^D	T-241	14.7 ^D
T-63	14.7 ^D	T-119	0.75 ^{NC}	T-242	14.7 ^D
T-64	11.1 ^{FR}	T-120	11.1 ^{FR}	T-243	14.7 ^D
T-65	11.1 ^{FR}	T-121	14.7 ^D	T-245	11.1 ^{FR}
T-78	14.7 ^D	T-122	14.7 ^D	T-246	11.1 ^{FR}
T-82	0.75 ^{NC}	T-123	11.1 ^{FR}	T-247	11.1 ^{FR}
T-84	14.7 ^D	T-124	11.1 ^{FR}	T-262	14.7 ^D
		T-125	11.1 ^{FR}	T-263	14.7 ^D

SN	Maximum Vapor Pressure (PSI)
T-264	14.7 ^D
T-265	14.7 ^D
T-270	14.7 ^D
T-271	14.7 ^D
T-272	0.75 ^{NC}
T-273	0.75 ^{NC}
T-274	0.75 ^{NC}
T-306	14.7 ^D
T-328	14.7 ^D
T-329	14.7 ^D
T-330	14.7 ^D
T-331	14.7 ^D
T-332	14.7 ^D
T-333	14.7 ^D
T-335	14.7 ^D
T-336	14.7 ^D
T-337	14.7 ^D
T-338	14.7 ^D
T-339	14.7 ^D
T-340	14.7 ^D
T-348	14.7 ^D
T-349	14.7 ^D
T-350	14.7 ^D
T-351	14.7 ^D
T-352	14.7 ^D
T-353	14.7 ^D
T-354	14.7 ^D
T-355	14.7 ^D

SN	Maximum Vapor Pressure (PSI)
T-356	14.7 ^D
T-360	11.1 ^{FR}
T-361	11.1 ^{FR}
T-368	14.7 ^D
T-371	11.1 ^{FR}
T-372	11.1 ^{FR}
T-382	0.75 ^{NC}
T-383	0.75 ^{NC}
T-384	0.75 ^{NC}
T-385	0.75 ^{NC}
T-386	0.75 ^{NC}
T-387	0.75 ^{NC}
T-394	4.0 ^{NC}
T-410	14.7 ^D
T-413	14.7 ^D
T-414	14.7 ^D
T-432	1.5 ^{NC}
T-521	14.7 ^D
T-524	14.7 ^D
T-525	14.7 ^D
T-530	14.7 ^D
T-532	11.1 ^{FR}
T-538	14.7 ^C
T-539	14.7 ^C
T-540	14.7 ^C
T-544	0.75 ^{NC}
T-548	0.75 ^{NC}
T-549	14.7 ^C

SN	Maximum Vapor Pressure (PSI)
T-551	14.7 ^C
T-552	14.7 ^C
T-553	0.75 ^{NC}
T-570	14.7 ^D
T-600	14.7 ^C
T-601	14.7 ^C
T-602	14.7 ^C
T-603	14.7 ^C
T-605	14.7 ^C
T-606	14.7 ^C
T-607	14.7 ^C
T-608	14.7 ^C
T-609	14.7 ^C
T-610	14.7 ^C
T-611	14.7 ^C
T-612	14.7 ^C
T-613	14.7 ^C
T-616	14.7 ^C
T-618	14.7 ^C
T-619	14.7 ^C
T-620	14.7 ^C
T-621	14.7 ^C
T-622	14.7 ^C
T-700	0.75 ^{NC}
T-701t	0.75 ^{NC}
T-702t	0.75 ^{NC}
T-703t	0.75 ^{NC}
T-765	11.1

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

SN	Maximum Vapor Pressure (PSI)
T-New	0.75 ^{NC}
T-998	11.1 ^{FR}

D	No limit or restriction on v.p. - the construction date is prior to the NSPS date. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
C	No limit or restriction on v.p. - capacity of tank is below the NSPS applicability capacity of 19,800 gals for NSPS Kb or 40,000 gals for NSPS K & Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
V	No limit or restriction on v.p. - the product stored does not meet the definition of a VOL under NSPS Kb. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
P	No limit or restriction on v.p. - the product does not meet the definition of a petroleum liquid under NSPS Ka. Reference to 14.7 psi is not intended to be a limitation on the maximum v.p. stored, but is included as a representative pressure of materials that might be stored at atmospheric conditions.
NC	V. P. restricted or limited - No Controls required; v.p. of product is below the limit that requires controls : 0.75 psia (5.2 kPa) for NSPS Kb (for tanks > 40,000 gal.); 4.0 psia (27.6 kPa) for NSPS Kb (for tanks with capacities between 20,000 and 40,000 gallons); or 1.5 psia (10.3 kPa) for NSPS K & Ka. See 40 C.F.R. § 60.112b(a) and 60.112a(a).
FR	V. P. restricted or limited - v.p. of the product cannot exceed 11.1 psia (76.6 kPa) based on using a Floating Roof as the control standard as required by the NSPS and/or MACT standard.

TANK 4 Solely for purposes of demonstrating compliance with the Tank PAL emission limits, the facility shall not exceed a total refinery crude feed rate of 100,000 barrels per day and a total of 36.6 MM bbls per consecutive twelve-month period. This limit is solely to demonstrate compliance with the emission limits in Specific Condition TANK 1 and does not establish any production rate, design capacity or other limitation. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

TANK 5 The facility shall maintain records of the total refinery crude feed rate to the facility on a daily basis and on a twelve-month rolling basis, both updated monthly. Such records shall be maintained on-site and submitted in accordance with General Provision #7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

TANK 6 The facility shall conduct an annual inventory of emissions of the pollutants listed in Specific Condition TANK 1. The emissions inventory shall be conducted each year, for the preceding calendar year (January 1-December 31), and shall be submitted to the in accordance with General Provision 7. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

TANK 7 Under the terms of 40 C.F.R., Part 60, Subpart Ka-Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced after May 18, 1978, and Prior to July 23, 1984, tanks T-108, T-109, 142, 143, 188, and 432 do not store a petroleum liquid with a true vapor pressure of 10.3 kPa (1.5 psia) or greater; and therefore are exempt from control requirements of Subpart Ka pursuant to 60.112a(a). Therefore, any petroleum liquid stored in these tanks shall have a vapor pressure less than 10.3 kPa (1.5 psia). Pursuant to 60.115a(a), the facility must maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [Reg.19.304 and 40 C.F.R. § 60.112a]

TANK 8 Tank T-532 is an affected facility under the terms of 40 C.F.R. 60, Subpart Ka-Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984. However, in accordance with 40 C.F.R., Part 63, Subpart CC-National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, § 63.640(n), the facility is only required to comply with the provisions of Subpart CC. [Reg.19.304 and 40 C.F.R. § 63.640(n)]

TANK 9 Under the terms of 40 C.F.R. § 60 Subpart Kb-Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, tanks T-7, T-88, T-103, T-113, T-119, T-247, T-372, T-765, and T-998 are affected facilities. The tanks are subject to the Subpart Kb requirements, which are summarized below. [§19.304 of Regulation 19, and 40 C.F.R. § 60.110b]

- a. Tank T-7, T-88, T-103, and T-113 have been equipped with external floating roofs as described in § 60.112b(a)(2). [§ 60.112b(a)]
- b. Tanks T-247, T-372, T-765, and T-998 have been equipped with internal floating roofs as described in § 60.112b(a)(1). [§ 60.112b(a)]
- c. Tank T-7, T-88, T-103, and T-113 have a mechanical shoe seal. Except as provided in § 60.113b(b)(4), the seals shall completely cover the annular space between the edge of the floating roof and the tank wall. [§ 60.112b(a)(2)(i)(A)]
- d. The secondary seals shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed by § 60.113b(b)(4). [§ 60.112b(a)(2)(i)(B)]
- e. Except for automatic bleeder vents and rim space vents, each opening in the floating roofs provides a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is equipped with a gasketed cover, seal, or lid that is to be maintained in a closed

position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are gasketed. Each emergency roof drain is provided with a slotted membrane fabric cover that covers at least 90 percent of the opening of the area. [§ 60.112b(a)(2)(ii)]

- f. The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. [§ 60.112b(a)(2)(ii)]
- g. Tanks T-7, T-88, T-103, T-113, T-119, T-247, T-372, T-765 shall meet the testing requirements of § 60.113b(b). [§ 60.113b]
- h. The facility has determined and will continue to determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel as prescribed by § 60.113b(b)(1)(i). [§ 60.113b(b)(1)]
- i. Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed at least once every 5 years after the date of the initial fill. [§ 60.113b(b)(1)(i)]
- j. Measurements of gaps between the tank wall and the secondary seal shall be performed at least once per year after the date of the initial fill. [§ 60.113b(b)(1)(ii)]
- k. If these sources cease to store a VOL for a period of one year or more, subsequent introduction of VOL into the vessels shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of 60.113b. [§ 60.113b(b)(1)(iii)]
- l. The facility shall determine gap widths and areas in the primary and secondary seals individually by the procedures outlined in (i), (ii), and (iii) as follows: [§ 60.113b(b)(2)]
 - i. The facility shall measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports. [§ 60.113b(b)(2)(i)]
 - ii. The facility shall measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location. [§ 60.113b(b)(2)(ii)]
 - iii. The total surface area of each gap described in paragraph (b)(2)(ii) of 60.113b shall be determined by using probes of various widths to measure

accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance. [§ 60.113b(b)(2)(iii)]

- m. The facility shall add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4). [§ 60.113b(b)(3)]
- n. The facility shall make necessary repairs or empty the storage vessels within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii). [§ 60.113b(b)(4)]
- o. The accumulated area of gaps between the tank wall and the mechanical shoe or liquid mounted primary seal shall not exceed 212 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm. [§ 60.113b(b)(4)(i)]
- p. One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface. [§ 60.113b(b)(4)(i)(A)]
- q. There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope. [§ 60.113b(b)(4)(i)(B)]
- r. The secondary seal is to meet the requirements of the following: [§ 60.113b(b)(4)(ii)]
 - i. The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in (b)(2)(iii). [§ 60.113b(b)(4)(ii)(A)]
 - ii. The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm. [§ 60.113b(b)(4)(ii)(B)]
 - iii. There are to be no holes, tears, or other openings in the seal or seal fabric. [§ 60.113b(b)(4)(ii)(C)]
- s. If a failure that is detected during inspections required by paragraph (b)(1), of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required by § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [§ 60.113b(b)(4)(iii)]
- t. The facility shall notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of 60.113b to afford the Administrator the opportunity to have an observer present. The Department has exercised its authority to grant permission for the 30-day notification period to be shortened to 5

days as indicated by Plantwide Condition #PW 10 (FF) and (GG). [§ 60.113b(b)(5)]

- u. The facility shall visibly inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. [§ 60.113b(b)(6)]
- v. If an external floating roof has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the facility shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL. [§ 60.113b(b)(6)(i)]
- w. For all inspections required by (b)(6), the facility shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of 60.113b is not planned and the facility could not have known about the inspection 30 days in advance of refilling the tank, the facility should notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received at least 7 days prior to the refilling. The Department has exercised its authority to grant permission for the 30-day and 7-day notification periods to be shortened to 5 days as indicated by Plantwide Condition PW 10 (FF) and (GG). [§ 60.113b(b)(6)(ii)]
- x. The facility shall keep records of tanks T-7, T-88, T-103, T-113, T-119, T-247, T-372, and T-765 as specified in § 60.115b(b)(3). The facility shall keep copies of all reports and records required by 60.115b for at least 2 years. [§ 60.115b(b)]
- y. The facility has or shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(a)(2), (b)(3), and (b)(4). [§ 60.115b(1)]
- z. Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), the facility shall furnish the Administrator with a report that contains: [§ 60.115b(b)(2)]
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in § 60.113b(b)(2) and (b)(3).
- aa. The facility shall keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain: [§ 60.115b(b)(3)]
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.

- iii. The calculations described in § 60.113b(b)(2) and (b)(3).
- bb. After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in (b)(2) and the date the vessel was emptied or the repairs made and date of repair. [§ 60.115b(b)(4)]
- cc. The facility shall keep copies of all records of tanks T-7, T-88, T-103, T-113, T-119, T-247, T-372, and T-765 as required by § 60.116b for at least 2 years. As an exception, the record required by § 60.116b(b) shall be kept for the lives of the sources. [§ 60.116b(a)]
- dd. The facility shall keep readily accessible records showing the dimensions of each vessel and an analysis showing the capacity of each vessel. [§ 60.116b(b)]
- ee. The facility shall maintain for each tank a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period. [§ 60.116b(c)]
- ff. The facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3). [§ 60.116b(e)]

TANK 10 Tanks T-19, T-24, T-59, T-272 through T-274, T-382 through T-387, T-544, T-548, and T-553 are exempted from the control requirements of Subpart Kb pursuant to 40 C.F.R. § 60.112b(a) because they have capacities greater than 151 m³ and store a liquid with a maximum true vapor pressure less than 5.2 kPa (0.75 psia). Therefore, any volatile organic liquid stored in these tanks shall have a vapor pressure less than 5.2 kPa (0.75 psia). These tanks are also subject to the following subpart Kb requirements, which are summarized below. [Reg.19.304 and 40 C.F.R. § 60.112b(a)]

- a. The facility shall as specified in § 60.116b(a) keep the records as required by § 60.116b(b) for the lives of the facilities.
- b. In accordance with § 60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.
- c. In accordance with § 60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 5.2 kPa (0.75 psia).
- d. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

TANK 11 Tank T-324 does not store a volatile organic liquid with a vapor pressure of 15.0 kPa (4.0 psia); and, therefore is exempt from the control requirements of Subpart Kb. As such, any volatile organic liquid stored in this tank shall have a vapor pressure less than 15.0 kPa (4.0 psia). This tank is also subject to the Subpart Kb requirements, which are summarized below. [Reg.19.304 and 40 C.F.R. § 60.110b(c)]

- a. The facility shall as specified in § 60.116b(a) keep the records as required by § 60.116b(b) for the lives of the facilities.

- b. In accordance with § 60.116b(b), the facility shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.
- c. In accordance with § 60.116b(d), the facility shall notify the Department within 30 days when the maximum true vapor pressure exceeds 15 kPa (4.0 psia).
- d. Pursuant to § 60.116b(e), the facility may determine the maximum true vapor pressure as described in § 60.116b(e)(1), (e)(2) and (e)(3).

TANK 12 Under the terms of 40 C.F.R. § 60 Subpart UU- Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, tanks T-24, T-41, T-112, T-382, T-383, T-384, T-385, T-386, T-387, and T-New are affected facilities. As such, in accordance with 60.472(c), the tank(s) shall not exhaust gases with an opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being cleared. [Reg.19.304 and 40 C.F.R. § 60.470]

TANK 13 Under the terms of 40 C.F.R. § 63 Subpart LLLLL- National Emission Standard for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing, tanks T-23, T-78, T-96, T-98, T-99, T-162, T-175, T-176, T-348, T-354 and T-544 are affected facilities. Each of the listed tanks is considered Group 2, and as such, in accordance with Table 1 to Subpart LLLLL, the tank(s) shall not exhaust gases with an opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being cleared. [Reg.19.304 and 40 C.F.R. § 63.8684(a)]

TANK 14 Records shall be kept onsite of any activity related to construction, reconstruction, or modification of any of the tanks listed in this section. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

SN-864 and 865

Dredge Engine and Booster Pump Engine

Source Description

These two sources are a 140 hp (SN-864) dredge engine and a 112 hp (SN-865) booster pump. Both engines are diesel-fired engines and will be used as part of the Corrective Action Management Unit facility being built in order to effectively treat sludge accumulations in the Solid Waste Management units that are targeted for remediation.

Specific Conditions

DS 1 The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition DS 6. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
864	Dredge Engine	PM ₁₀	0.1	0.2
		SO ₂	0.3	1.3
		VOC	0.9	3.8
		CO	0.3	1.4
		NO _x	0.9	3.8
865	Booster Pump Engine	PM ₁₀	0.1	0.3
		SO ₂	0.3	1.1
		VOC	0.8	3.2
		CO	0.2	0.9
		NO _x	0.8	3.2

DS 2 The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition DS 6. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
864	Dredge Engine	PM	0.1	0.2
		Ammonia	0.9	3.5
865	Booster Pump Engine	PM	0.1	0.3
		Ammonia	0.7	2.9

Lion Oil Company
Permit #: 0868-AOP-R10
AFIN: 70-00016

- DS 3 The permittee shall not emit gasses from SN-864 and SN-865 which exhibit an opacity of greater than 20% as measured by EPA Reference Method 9. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]
- DS 4 The permittee shall comply with 40 C.F.R. § 63 Subpart ZZZZ for SN-864 and SN-865 by meeting the requirements of 40 C.F.R. § 60 Subpart IIII. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- DS 5 The permittee must operate and maintain SN-864 and 865 according to the manufacture's written instructions or procedures developed by Lion Oil that are approved by the manufacturer. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- DS 6 The permittee must use a fuel in SN-864 and SN-865 that meets the specifications of 40 C.F.R. § 80.510(b) for non-road diesel fuel. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- DS 7 Lion Oil must comply with the emission standards specified in § 60.4204(b). Compliance with this condition will be shown by compliance with Specific Condition DS 5. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]

SN-867, 868, 870, and 871

OCC Generator

IT Generator

Fire Pump Engines

Source Description

The OCC generator is a 134 hp diesel fired generator.

The IT Generator is a 34 hp natural gas fired generator.

SN-870 and 871 are two 800 hp diesel-fired emergency fire pump engines.

Specific Conditions

- ENG 1. The permittee shall not exceed the emission rates set forth in the following table.
 The permittee shall demonstrate compliance with this condition by compliance with
 Specific Condition DS 6. [Reg.19.501 *et seq.* and 40 C.F.R. § 52 Subpart E]

SN	Description	Pollutant	lb/hr	tpy
867	OCC Generator	PM ₁₀	0.3	0.1
		SO ₂	0.3	0.1
		VOC	0.4	0.1
		CO	0.9	0.3
		NO _x	4.2	1.1
868	IT Generator	PM ₁₀	0.1	0.1
		SO ₂	0.1	0.1
		VOC	0.1	0.1
		CO	0.3	0.1
		NO _x	1.6	0.4
870	Fire Pump Engine	PM ₁₀	0.3	0.1
		SO ₂	0.1	0.1
		VOC	0.6	0.2
		CO	4.6	1.2
		NO _x	8.5	2.2

SN	Description	Pollutant	lb/hr	tpy
871	Fire Pump Engine	PM ₁₀	0.3	0.1
		SO ₂	0.1	0.1
		VOC	0.6	0.2
		CO	4.6	1.2
		NO _x	8.5	2.2

ENG 2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by compliance with Specific Condition DS 6. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Description	Pollutant	lb/hr	tpy
867	OCC Generator	PM	0.3	0.1
		Ammonia	0.8	0.2
868	IT Generator	PM	0.1	0.1
		Ammonia	0.1	0.1
870	Fire Pump Engine	PM	0.3	0.1
		HAPs	0.01	0.01
871	Fire Pump Engine	PM	0.3	0.1
		HAPs	0.01	0.01

ENG 3. The permittee shall not emit gasses from SN-867, 870, and 871 which exhibit an opacity of greater than 20% as measured by EPA Reference Method 9. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

ENG 4. The permittee shall not emit gasses from SN-868 which exhibit an opacity of greater than 5% as measured by EPA Reference Method 9. [Reg.18.501 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

ENG 5. The permittee shall not operate the emergency generator any of SN-867, 868, 870, or 871 in excess 500 total hours each (emergency and non-emergency) per calendar year in order to demonstrate compliance with the annual emission rate limits. Emergency operation in excess of these hours may be allowable but shall be reported and will be evaluated in accordance with Reg.19.602 and other applicable regulations. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

ENG 6. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition ENG 5. The permittee shall update these records by the fifteenth day of the month following the month to which the records pertain. The calendar year totals and each individual month's data shall be maintained on-site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

- ENG 7. The permittee shall for SN-867 and 868 operate and maintain engine and control device per manufacturer's instructions. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 8. The permittee shall for SN-867 and 868 install a non-resettable hour meter. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 9. The permittee must for SN-867 and 868 keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 10. The permittee must keep records of all maintenance for SN-867 and 868. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 11. The permittee shall for SN-867 and 868 change oil and filter and inspect hoses and belts every 500 hours or annually whichever comes first. For SN-867 the permittee shall inspect air cleaner every 1000 hours or annually whichever comes first. For SN-868 the permittee shall inspect the sparkplugs every 1000 hours or annually whichever comes first. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 12. The permittee shall comply with 40 C.F.R. § 63 Subpart ZZZZ for SN-870 and SN-871 by meeting the requirements of 40 C.F.R. § 60 Subpart IIII. [Reg.19.304 and 40 C.F.R. § 63, Subpart ZZZZ]
- ENG 13. The permittee must use a fuel in SN-870 and SN-871 that meets the specifications of 40 C.F.R. § 80.510(b) for non road diesel fuel. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- ENG 14. The permittee must operate and maintain SN-870 and 871 according to the manufactures' written instructions or procedures developed by Lion Oil that are approved by the manufacturer. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- ENG 15. Lion Oil must comply with the emission standards specified in § 60.4205(c). Compliance with this condition will be shown by compliance with Specific Condition DS 5. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- ENG 16. Lion Oil must install a non resettable hour meter on SN-870 and 871. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]
- ENG 12. Lion Oil must not operate either SN-870 or 871 more than 100 hours per calendar year for the purposes of maintenance checks and readiness testing. Lion Oil may use either SN-870 or 871 for non emergency purposes for no more than 50 hours per calendar year. Those 50 hours must be included in the 100 hours allowed for maintenance and readiness. [Reg.19.304 and 40 C.F.R. § 60, Subpart IIII]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Lion Oil Company will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis. Lion Oil shall comply with the requirements outlined in the following table until the compliance date specified in the table.

Rule Requirements	Interim Requirement	Final Compliance Deadline
Requirements for “maintenance vents” in 40 CFR 63.643(c)	Comply with the general duty requirements in 63.642(n) and 63.643(d), from the effective date of the rule until the final compliance deadline	August 1, 2017
New or revised operating limits for FCCUs in 63.1564(a)(2) and 63.1565(a)(2)		August 1, 2017
Startup, shutdown, and malfunction and hot standby provisions for fluid catalytic cracking units in 63.1564(a)(5)	Comply with the general duty requirements in 63.1570(c), from the effective date of the rule until the final compliance deadline	August 1, 2017
Startup, shutdown, and malfunction and hot standby provisions for fluid catalytic cracking units in 63.1565(a)(5)	Comply with the general duty requirements in 63.1570(c), from the effective date of the rule until the final compliance deadline	August 1, 2017
Catalytic reforming units, depressuring and purging requirements in 63.1566(a)(4) and tables 15 and 16		February 1, 2019
Startup, Shutdown, Malfunction and other provisions for sulfur recover units in 63.1568(a)(4)	Comply with the general duty provisions in 63.1570(c) and (d) from the effective date of the rule until final compliance deadline	August 1, 2017

Miscellaneous Process Vent requirements in 63.644(c)	Continue to comply with 40 CF 63.644(c), as applicable prior to the February 1, 2016 effective date, until the Final Compliance Deadline	February 1, 2017
Storage Vessel provisions in 63.660 and including the requirements of 63.640 and 63.646, which contains definitions and deadlines related to compliance with 63.660	Continue to comply with the storage vessel requirements of NSPS, subparts K, Ka, Kb, MACT CC, and the Title V operating permit until the Final Compliance Deadline	February 1, 2018
Emissions, Operating, Monitoring and other requirements for CCU in 63.1564 and 63.1565(a)(1), (3),(4), (b), and (c)	Continue to comply with the requirements of 63.1564 and 63.1565, as applicable, prior to the February 1, 2016 effective date, until the Final Compliance Deadline	August 1, 2017
Monitoring, Installation and Maintenance Requirements in 63.1572(c)(1)-(5)	Continue to comply with the requirements of 63.1572, as applicable, prior to the February 1, 2016 effective date, until the Final Compliance Deadline	February 1, 2017
Conduct performance tests in 1564(b)(2)	n/a	150 days after compliance with 63.1564(a)(2)(150 days after August 1, 2017)
Performance testing requirements in NSPS, subpart Ja	n/a	August 1, 2017

SECTION VI: PLANTWIDE CONDITIONS

- PW 1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Reg.19.704, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- PW 2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Reg.19.410(B) and 40 C.F.R. § 52 Subpart E]
- PW 3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Reg.19.702 and/or Reg.18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- PW 4. The permittee must provide:
- a. Sampling ports adequate for applicable test methods;
 - b. Safe sampling platforms;
 - c. Safe access to sampling platforms; and
 - d. Utilities for sampling and testing equipment.
- [Reg.19.702 and/or Reg.18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- PW 5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Reg.19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
- PW 6. This permit subsumes and incorporates all previously issued air permits for this facility. [Reg. 26 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

- PW 7. The facility shall not exceed the emission rates set forth in the following table. Compliance with these limits shall be demonstrated by completing an annual emissions inventory, refinery crude feed rate limits, and maximum vapor pressure restrictions. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

SN	Pollutant	lb/hr	tpy
Facility	HAPs	391.3	1062.7

- PW 8. Pipeline quality natural gas is that which meets the tariff requirements of any major transmission company. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
- PW 9. The facility is subject to 40 C.F.R. §61 Subpart FF – *National Emission Standards for Benzene Waste Operations* because it is a petroleum refinery. [Reg.19.304 and 40 C.F.R. § 61.340(a)]
- The facility has identified itself as having total annual benzene quantity from facility waste of equal to or greater than 10 Mg/yr. The facility shall follow any applicable requirements of § 61.342(e).
 - The facility shall keep the records required by § 61.356(a) and (b).
 - The facility shall follow the reporting requirements of § 61.357(c).
- PW 10. The facility has sources which are subject to the provisions of 40 C.F.R. § 63 Subpart CC-*National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*, which are summarized below.
- For the purpose of MACT Subpart CC, the affected source shall comprise all emission points, in combination, listed in § 63.640(c)(1) through (c)(7) that are located at a single refinery plant site. *Note: (c)(6) does not apply.*
 - All miscellaneous process vents from petroleum refining process units meeting the criteria in § 63.640 (a);
 - All storage vessels associated with petroleum refining process units meeting the criteria in § 63.640(a);
 - All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in § 63.640(a);
 - All equipment leaks from petroleum refining process units meeting the criteria in § 63.640(a);
 - All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in § 63.640(a);
 - All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial

Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in § 63.640(a).

- b. Pursuant to § 63.640(d), the affected source does not include the emission points listed in paragraphs (d)(1) through (d)(5).
 - i. Stormwater from segregated stormwater sewers;
 - ii. Spills;
 - iii. Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in § 63.641 of MACT Subpart CC, for less than 300 hours during the calendar year.
 - iv. Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents.
 - v. Emission points routed to a fuel gas system, as defined in § 63.641 of Subpart CC. No testing, monitoring record keeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.
- c. The owner or operator shall keep a log of the storage vessels in § 63.640(e)(1) and (e)(2) that are subject to Subpart CC.
- d. The owner or operator shall keep a log of the miscellaneous process vents from distillation units in § 63.640(f)(1) through (f)(5) that are subject to Subpart CC.
- e. The facility shall keep a log of the processes specified in paragraphs § 63.646(g)(1) through (g)(7) that are exempt from Subpart CC.
- f. Sources subject to Subpart CC shall achieve compliance with the subpart by the dates specified in § 63.640(h).
- g. Sources that are added, reconstructed, have additions, or are otherwise modified shall achieve compliance in accordance with § 63.640(i), (j), and (k).
- h. If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, or gasoline loading rack that meets the criteria in § 63.640 (c)(1) through (c)(7) is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in § 63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to § 63.640 (i) or (j), the requirements in § 63.640 (l)(1) through (l)(3) shall apply. The facility shall keep a log to show that it has complied with the provisions of 63.2390.
- i. If a change that does not meet the criteria in § 63.640(l) is made to a petroleum refining process unit subject to MACT Subpart CC, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §

63.641), then the owner or operator shall comply with the requirements of MACT Subpart CC for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1. A compliance schedule for the change shall be submitted to the Administrator in accordance with § 63.640(m)(1) through (3).

- j. The following shall apply to the facility for the overlap of subpart CC with other regulations for storage vessels in § 63.640(n)(1) through (7).

Existing Regulation	Source	Group	Comply with	Comments
40 C.F.R. § 60, Subpart Kb	Existing	Group 1 Group 2	40 C.F.R. § 60, Subpart Kb	
40 C.F.R. § 60, Subpart Kb	New	Group 1	40 C.F.R. § 63, Subpart CC	
40 C.F.R. § 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. § 60, Subpart Kb	If source is subject to control requirements in Subpart Kb, comply with Kb instead of CC.
40 C.F.R. § 60, Subpart Kb (see comment)	New	Group 2	40 C.F.R. § 63, Subpart CC	If source is not required to apply controls by Subpart Kb, comply with CC instead of Kb.
40 C.F.R. § 60, Subpart K or Ka	New and Existing	Group 1	40 C.F.R. § 63, Subpart CC	
40 C.F.R. § 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. § 60, Subpart K or Ka	If source is subject to control requirements in Subparts K or Ka, comply with K or Ka instead of CC.
40 C.F.R. § 60, Subpart K or Ka	New and Existing	Group 2	40 C.F.R. § 63, Subpart CC	If source is not required to apply controls by Subparts K or Ka, comply with CC instead of K or Ka.

- k. The following shall apply to the facility for the overlap of subpart CC with other regulations for wastewater in § 63.640(o)(1) and (2).

Existing Regulation	Source	Group	Comply with	Comments
40 C.F.R. § 60, Subpart QQQ	New and Existing	Group 1	40 C.F.R. § 63, Subpart CC	
40 C.F.R. § 61, Subpart FF	New and Existing	Group 1	40 C.F.R. 61, Subpart FF	

Existing Regulation	Source	Group	Comply with	Comments
40 C.F.R. § 63, Subpart G	New and Existing	Group 1 Group 2	40 C.F.R. § 63, Subpart G, §§ 63.133-63.137, 63.140	Applies to equipment used in storage and conveyance of wastewater streams.
			40 C.F.R. § 61, Subpart FF, and 40 C.F.R. § 63, Subpart G, §§ 63.138, 63.139	Applies to treatment and control of wastewater streams.
			40 C.F.R. § 63, Subpart G, §§ 63.143-63.148	Applies to monitoring and inspections of equipment and recordkeeping and reporting requirements.

- l. After the compliance dates specified in § 63.640(h) equipment leaks that are also subject to the provisions of 40 C.F.R. §§ 60 and 61 are required to comply only with the provisions of MACT Subpart CC.
- m. The facility shall refer to Table 6 of Subpart CC in accordance with § 63.642(c) for in order to reference specific provisions of Subpart A of Part 63 that apply and those that do not apply.
- n. Pursuant to § 63.642(d), initial performance tests and initial compliance determinations shall be required only as specified in MACT Subpart CC. A log showing compliance with §§ 63.642(d)(1) through (4) shall be kept.
- o. Pursuant to § 63.642(e), each owner or operator of a source subject to MACT Subpart CC shall keep copies of all applicable reports and records required by MACT Subpart CC for at least 5 years except as otherwise specified in MACT Subpart CC. All applicable records shall be maintained in such a manner that they can be readily accessed. Records for the most recent 2 years shall be retained onsite at the source or shall be accessible from a central location by computer. The remaining 3 years of records may be retained offsite. Records may be maintained in hard copy or computer- readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.
- p. Pursuant to § 63.642(f), all reports required under MACT Subpart CC shall be sent to the Administrator at the addresses listed in § 63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.
- q. Pursuant to § 63.2390(h), the owner or operator of a new source subject to the requirements of MACT Subpart CC shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of 63.2390.
- r. Pursuant to § 63.642(i), the owner or operator of an existing source shall demonstrate compliance with the emission standard in § 63.642(g) by following the procedures specified in § 63.642(k) for all emission points, or by following

the emissions averaging compliance approach specified in § 63.642(l) for specified emission points and the procedures specified in § 63.642(k) for all other emission points within the source. The facility shall keep a log to demonstrate compliance with this provision.

- s. Pursuant to § 63.642(j), the owner or operator of a new source shall demonstrate compliance with the emission standard in § 63.642(h) only by following the procedures in § 63.642(k). The owner or operator of a new source may not use the emissions averaging compliance approach. The facility shall keep a log to demonstrate compliance with this provision.
- t. The owner or operator of a Group 1 miscellaneous process vent as defined in § 63.641 shall comply with the requirements of either § 63.643(a)(1) or (a)(2). A log shall be kept to demonstrate compliance with these provisions.
- u. The facility shall keep a log to demonstrate compliance with the provisions of § 63.644(a) for Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in § 63.643(a).
- v. The facility shall keep a log to demonstrate how it has complied with § 63.644(c) which requires the owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with § 63.644(a) to follow additional constraints outlined in § 63.644(c).
- w. Pursuant to § 63.644(d), the owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of 63.644. In order to establish the range, the information required in § 63.654(f)(1)(3) shall be submitted in the Notification of Compliance Status report.
- x. Pursuant to § 63.644(e) Each owner or operator of a control device subject to the monitoring provisions of 63.644 shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of 63.644. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in § 63.654(g)(6), or failure to perform procedures required by 63.644 shall constitute a violation of the applicable emission standard of MACT Subpart CC.
- y. The facility shall comply with the test measures and procedures for miscellaneous process vents in § 63.645.
- z. Pursuant to § 63.645(h), the owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. A log of these calculations and supporting assumptions shall be kept to demonstrate compliance with § 63.645.

- aa. The facility shall keep a log to demonstrate that the compliance determination for § 63.645(i) has been met.
- bb. The facility shall comply with the storage vessel provisions of § 63.646. Notices of Compliance Status Report shall be submitted to the Administrator as required by this section.
- cc. Pursuant to § 63.646(e), when complying with the inspection requirements of § 63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to MACT Subpart CC are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.
- dd. Pursuant to § 63.646(f), the paragraphs (f)(1), (f)(2), and (f)(3) of 63.646 apply to Group 1 storage vessels at existing sources:
 - i. If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.
 - ii. Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.
 - iii. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
- ee. Pursuant to § 63.646(g), failure to perform inspections and monitoring required by 63.646 shall constitute a violation of the applicable standard of MACT Subpart CC.
- ff. The provisions of 40 C.F.R. § 63.646(l) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 C.F.R. §§ 63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii). The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.
- gg. The provisions of 40 C.F.R. § 63.654(h)(2)(C)(ii) provide state permitting agencies with the authority to waive or modify the notification requirements of 40 C.F.R. § 63.120(b)(1) or § 63.120(b)(2) of Subpart G of part 63. The notification requirements of these sections are hereby modified as follows: Lion Oil shall provide notice, as required herein, by facsimile transmittal five (5) business days prior to the scheduled event in lieu of providing 30 days prior written notice to the Department. This written notice may be submitted electronically to the local district air inspector and the ADEQ Air Division Enforcement Branch Technical Assistance Manager.

- hh. The facility shall comply with the wastewater provisions of 63.647 where applicable. The facility shall maintain a log to demonstrate that it has complied with the requirements of 63.647.
- ii. The facility shall comply with the equipment leak standards of § 63.648. Portions of § 63.648 overlap with the requirements already listed for Subpart VV in the Fugitive Emissions (SN- 854) section of this permit. The facility may combine the requirements of that section with § 63.648 and keep all necessary reports in one log. In any case, the facility shall keep a log to demonstrate compliance with § 63.648.
- jj. Pursuant to § 63.648(h), each owner or operator of a source subject to the provisions of MACT Subpart CC must maintain all records for a minimum of 5 years.
- kk. The facility shall comply with the gasoline loading rack provisions of § 63.650(a). The facility shall keep a log to demonstrate that all requirements of § 63.650 have been met.
- ll. The facility shall keep in a log, methods used and affected equipment for any of the emissions averaging provisions that are used in § 63.652. The facility shall also follow the requirements for § 65.653. Records for monitoring, recordkeeping, and implementation plans shall also be kept in the same log.
- mm. The facility shall comply with the provisions of § 63.654(a) and keep a log of how it has complied with those provisions.
- nn. The facility shall comply with the provisions of § 63.654(b) and keep a log of how it has complied with those provisions.
- oo. The facility shall comply with the provisions of § 63.654(d)(1) through (6) and keep a log of how it has complied with those provisions.
- pp. Pursuant to § 63.654(e), the facility shall submit the reports listed in paragraphs (e)(1) through (e)(3) except as provided in paragraph (h)(5) of § 63.654, and shall keep records as described in paragraph (i) of § 63.654.
 - i. A Notification of Compliance Status report as described in paragraph (f) of § 63.654.
 - ii. Periodic Reports as described in paragraph (g) of § 63.654.
 - iii. Other reports as described in paragraph (h) of § 63.654.
- qq. The facility shall keep a log to show that it has complied with § 63.654(f)(1) through (6).
- rr. The facility shall keep a log to show that it has complied with the requirements of § 63.654(g)(1) through (g)(8).
- ss. The facility shall keep a log demonstrating that it has complied with the submittal requirements of § 63.654(h).
- tt. The facility shall keep a log of the records required by § 63.654(i).

- uu. All other information required to be reported under paragraphs § 63.654(a) through (h) shall be retained for 5 years.
- vv. Compliance demonstrations begin on the first of the next calendar month following the beginning of the permit requirement. For those sources not subject to a rolling average requirement in the permits preceding AR-868-R0, rolling average requirements do not begin until twelve months after the issuance of this permit. Although on-going compliance with annual limits will be demonstrated with twelve-month rolling averages, violation of annual limits can only occur once per calendar year.

PW 11. All sources specified as fuel gas combustion devices under the provisions of 40 C.F.R. § 60, Subpart J-*Standards of Performance for Petroleum Refineries* in the specific conditions of this permit are subject to the requirements outlined below: [Reg.19.304 and 40 C.F.R. § 60.100]

- a. “NSPS Subpart J quality gas” or “Refinery fuel gas” is defined as any gas which is generated at a petroleum refinery and which is combusted, with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. “Fuel gas” is defined as any gas which is generated at a petroleum refinery and which is combusted with the exception of gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. [§ 60.101(d)]
- b. The permittee shall not burn fuel gas that exceeds the concentration set forth in the following table. Compliance with this condition shall be demonstrated by compliance with Subpart J. [§ 60.104]

Table 1 – Fuel Gas Sulfur Limits

Sources	Pollutant	mg/dscm	gr/dscf	ppmvd
All refinery Fuel Gas Combustion Devices	H ₂ S	230	0.10	162
	SO ₂	-	-	20

- c. The facility shall monitor emissions and operations by installing one of the following:
 - i. An SO₂ CEMs on the fuel gas combustion exhaust [§ 60.105(a)(3)], or
 - ii. An H₂S CEMS on the fuel gas before being combusted. [§ 60.105(a)(4)]
- d. Excess emissions that shall be determined and reported are defined as follows: [60.105(e)]
 - i. All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

- ii. All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
- e. The test methods shall be conducted according to § 60.106(e)(1) for H₂S CEMs or § 60.106(e)(2) and § 60.106(f)(1) for SO₂ CEMs. [§ 60.106]
- f. The reporting and recordkeeping requirements shall be kept as required in § 60.107(d), (e), and (f). [§ 60.107]
- g. The combustion in a flare of a process upset gas or fuel gas that is released to the flares as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph. [§ 60.104(a)(1)]

PW 12. The facility is subject to the provisions of 40 C.F.R. § 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, which are summarized below. [Reg. 19.304 and 40 C.F.R. § 63.1561]

- a. The permittee shall meet each applicable emission limitation in Table 1 of subpart UUU. If the catalytic cracking unit is subject to the NSPS for PM in § 60.102 of, the permittee must meet the emission limitations for NSPS units. [§ 63.1564(a)(1)]
- b. The permittee shall meet each applicable emission limitation in Table 8 of subpart UUU. If the catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in § 60.103 of this chapter, the permittee must meet the emission limitations for NSPS units. [§ 63.1565(a)(1)]
- c. The permittee shall meet each applicable operating limit in Table 2 and Table 9 of Subpart UUU. [§ 63.1564(a)(2), § 63.1565(a)(2)]
- d. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures of the plan. [§ 63.1564(a)(3), § 63.1565(a)(3)]
- e. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in § 63.1564(b) and § 63.1565(b). [§ 63.1564(b), § 63.1565(b)]
- f. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in § 63.1564(c) and § 63.1565(c). [§ 63.1564(c), § 63.1565(c)]
- g. The permittee shall meet each applicable emission limitation in Table 15 and Table 22 of Subpart UUU. [§ 63.1566(a)(1), § 63.1567(a)(1)]
- h. The permittee shall meet each applicable operating limit in Table 16 and Table 23 of Subpart UUU. [§ 63.1566(a)(2), § 63.1567(a)(2)]

- i. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures of the plan. [§ 63.1566(a)(3), § 63.1567(a)(3)]
- j. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in § 63.1566(b) and § 63.1567(b). [§ 63.1566(b), § 63.1567(b)]
- k. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in § 63.1566(c) and § 63.1567(c). [§ 63.1566(c), § 63.1567(c)]
- l. The permittee shall meet each applicable emission limitation in Table 29 of sub in § 60.104 part UUU. If the sulfur recovery unit is subject to the NSPS for sulfur oxides in § 60.104 of this chapter, the permittee must meet the emission limitations for NSPS units. [§ 63.1568(a)(1)]
- m. The permittee shall meet each applicable operating limit in Table 30 of Subpart UUU. [§ 63.1568(a)(2)]
- n. The permittee shall prepare an operation, maintenance, and monitoring plan according to the requirements in § 63.1574(f) and operate at all times according to the procedures of the plan. [§ 63.1568(a)(3), § 63.1569(a)(3)]
- o. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods referenced in § 63.1568(b). [§ 63.1568(b)]
- p. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in § 63.1568(c). [§ 63.1568(c)]
- q. For each bypass line, the permittee shall select and comply with one of the options given in § 63.1569(a)(1) and meet applicable work practice standards given in Table 36 of Subpart UUU. [§ 63.1569(a)(1)]
- r. As applicable, the permittee shall demonstrate initial compliance with the work practice standards by the methods listed in § 63.1569(b). [§ 63.1569(b)]
- s. As applicable, the permittee shall demonstrate continuous compliance with the work practice standards by the methods referenced in § 63.1569(c). [§ 63.1569(c)]
- t. The permittee shall comply with all of the non-opacity standards in Subpart UUU during the times specified in § 63.6(f)(1). [§ 63.1570(a)]
- u. The permittee shall comply with the opacity and visible emission limits of Subpart UUU during the times specified in § 63.6(h)(1). [§ 63.1570(b)]
- v. The permittee shall always operate and maintain affected sources, including air pollution control and monitoring equipment, according to the provisions in § 63.6(e)(1)(i). During the period between the compliance date specified and the date upon which continuous monitoring systems have been installed and validated

and any applicable operating limits have been set, the permittee must maintain a log detailing the operation and maintenance of the process and emissions control equipment. [§ 63.1570(c)]

- w. The permittee must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in § 63.6(e)(3). [§ 63.1570(d)]
- x. During periods of startup, shutdown, and malfunction, the permittee shall operate in accordance with the SSMP. [§ 63.1570(e)]
- y. The permittee shall report each instance in which it did not meet each emission limitation and each operating limit in MACT Subpart CC that applies. This includes periods of startup, shutdown, and malfunction. The permittee also must report each instance in which it did not meet the work practice standards in MACT Subpart CC that apply. These instances are deviations from the emission limitations and work practice standards in MACT Subpart CC. These deviations must be reported according to the requirements in § 63.1575. [§ 63.1570(f)]
- z. Consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the permittee demonstrates to the Administrator's satisfaction that it was operating in accordance with the SSMP. The SSMP must require that good air pollution control practices are used during those periods. The plan must also include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in § 63.6(e) and the contents of the SSMP. [§ 63.1570(g)]
- aa. The permittee shall comply with the applicable portions of § 63.1571 – Performance Tests and Initial Compliance Demonstration. [§ 63.1571]
- bb. As applicable, the permittee shall install, operate, and maintain each continuous emission monitoring system according to the following: [§ 63.1572(a)]
 - i. The permittee must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of Subpart UUU.
 - ii. If the permittee uses a continuous emission monitoring system to meet the NSPS CO or SO₂ limit, the permittee must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in § 63.8 and Table 40 of Subpart UUU. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.
 - iii. As specified in § 63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

- iv. Data must be reduced as specified in § 63.8(g)(2).
- cc. As applicable, the permittee shall install, operate, and maintain each continuous parameter monitoring system according to the following: [§ 63.1572(c)]
- dd. The permittee shall install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately. The permittee shall also meet the equipment specifications in Table 41 of Subpart UUU if pH strips or colorimetric tube sampling systems are used.
- ee. The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. The permittee must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).
- ff. Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.
- gg. Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.
- hh. Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.
- ii. The permittee shall monitor and collect data according to the following: [§ 63.1572(d)]
 - i. Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the permittee must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.
 - ii. The permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of Subpart UUU, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. The permittee must use all the data collected during all other periods in assessing the operation of the control device and associated control system.
- jj. The permittee shall identify any specifically applicable requirements related to the monitoring alternatives as necessary. [§ 63.1573]

- kk. The permittee shall comply with the applicable notification requirements, reporting requirements, and record keeping requirements. [§ 63.1574, § 63.1575, § 63.1576]
 - ll. The permittee shall identify applicable requirements pertaining to Subpart UUU as the information becomes available. The latest updates to applicable requirements shall be submitted to ADEQ along with future application materials. The information will be used to update this permit condition to more specifically list applicable requirements. [19.304 of Regulation]
- PW 13. This facility is subject to the federal regulations identified herein at the time of permit issuance. The source(s) affected by these regulations must comply with the most recent version as published in the Code of Federal Regulations. The source(s) must comply with all applicable federal regulations, whether or not accurately and specifically identified in this permit or its appendices. Regulations attached to this permit are for illustrative purposes only and are not deemed to be enforceable as attached unless the attached version is the most current and effective revision as cited and published in the C.F.R. Regardless of the form of the attached subparts, the source(s) are always subject to the most recent version of the subparts. In addition, subsequent changes to the subparts do not necessarily exempt the source from existing requirements contained in this air permit. [§19.304 of Regulation 19 and 40 C.F.R. §52 Subpart E]

Title VI Provisions

- PW 14. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 C.F.R. §82, Subpart E]
- a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
 - b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
 - c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
 - d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.
- PW 15. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 C.F.R. §82, Subpart F]
- a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
 - b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

- c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
- d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" as defined at §82.152.)
- e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
- f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

PW 16.If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 C.F.R. §82, Subpart A, Production and Consumption Controls.

PW 17.If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 C.F.R. §82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

- a. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.

PW 18.The permittee can switch from any ozone-depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 C.F.R. §82, Subpart G, "Significant New Alternatives Policy Program".

PW 19.Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements, as of the date of permit issuance, included in and specifically identified in the following table of this condition. The permit specifically identifies the following as applicable requirements based upon the information submitted by the permittee in an application dated May 27, 2011.

Applicable Regulations

Source No.	Regulation	Description
Facility	Ark. Pollution Control and Ecology Commission Regulation 19	Compilation of Regulation of the Arkansas State Implementation Plan for Air Pollution Control

Source No.	Regulation	Description
Facility	Ark. Pollution Control and Ecology Commission Regulation 26	Regulations of the Arkansas Operating Air Permit Program
SN-850, SN-862	40 CFR Part 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial Steam Generating Units
SN-864, SN-865	40 CFR Part 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821 (a,b,c), SN-824, SN-828, SN-830, SN-832, SN-842, SN-844, SN-850, SN-857, SN-860, SN-861, SN-862	40 CFR Part 60, Subpart J	Standards of Performance for Petroleum Refineries
SN-809, SN-822, SN-823	40 CFR Part 60, Subpart Ja	Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
T-532, T-108, T-109, T-188	40 CFR Part 60 Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification commenced after May 18, 1978 and prior to July 23, 1984
T-7, T-88, T-103, T-24, T-113, T-272, T-273, T-274, T-382 through T-387, T-544, T-553, T-19, T-59, T-247, T-372, T-998	40 CFR Part 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Storage Vessels) for which Construction, Reconstruction, or Modification commenced after July 23, 1984
T-382, T-383, T-24, T-41, T-78, T-112, T-382 through T-387, T-New	40 CFR Part 60, Subpart UU	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
Equipment Leaks*	40 CFR Part 60 Subpart VV	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Lion Oil Company
 Permit #: 0868-AOP-R10
 AFIN: 70-00016

Source No.	Regulation	Description
#4 Crude Unit, #6 Hydrotreater/Isomerization Unit, #12 Distillate Hydrotreater, #17 Sulfur Recovery Plant*, and #19 PMA Plant	40 CFR Part 60, Subpart GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Facility	40 CFR Part 61 Subpart FF	National Emission Standard for Benzene Waste Operations
Facility*, T-36, T-61, T-62, T-64, T-65, T-66, T-67, T-85, T-89, T-120, T-123, T-124, T-125, T-126, T-128, T-245, T-246, T-360, T-361, T-371, T-532, T-536, T-998	40 CFR Part 63, Subpart CC	National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries
SN-854 (Crude Oil Unloading Fugitive Components Only), SN-869	40 CFR Part 63, Subpart EEEE	National Emission Standard for Hazardous Air Pollutants: Organic Liquids Distribution
SN-841A, SN-849, SN-864, SN-865, SN-866, SN-867, SN-868	40 CFR Part 63, Subpart ZZZZ	National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

The permit specifically identifies the following as inapplicable based upon information submitted by the permittee in an application dated May 27, 2011.

Inapplicable Regulations

Source No.	Regulation	Description
SN-828	40 C.F.R. 60 Subpart Dc	Units were installed before 1989.
SN-849, SN-866, SN-867	40 CFR Part 60, Subpart IIII	Units were constructed before July 11, 2005.
SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821 (a,b,c), SN-	40 C.F.R. 60, Subpart Ja	Constructed prior to May 14, 2007.

Source No.	Regulation	Description
824, SN-828, SN-830, SN-832, SN-842, SN-844, SN-850, SN-857, SN-860, SN-861, SN-862		
SN-841A, SN-868	40 CFR Part 60, Subpart JJJJ	Units were constructed before June 12, 2006.
T-610, T-108, T-109, T-142, T-143	40 C.F.R. 60, Subpart Ka	Smaller than 40,000 gallons. Exempt from controls because these tanks store a petroleum liquid with a maximum true vapor pressure less than 10.3 kPa (1.5 psia).
T-24, T-113, T-272 to T-274, T-382-387, T-553, T-544, T-553	40 C.F.R. 60, Subpart Kb	Exempt because they store a liquid with a maximum true vapor pressure less than 5.2 kPa (.75 psia).
T-324		Exempt because capacity greater than or equal to 75 m ³ , but less than 151 m ³ storing a liquid with a maximum true vapor pressure less than 15.0 kPa (4.0 psia).
T-538, T-539, T-540, T-549 to T-552, T-600 to T-609, T-611, and T-612		Smaller than 40 m ³ .
All tanks not previously identified	40 C.F.R. 60, Subpart K, Ka, and Kb	Constructed prior to June 11, 1973; Constructed prior to May 19, 1978; Constructed prior to July 23, 1984 (as applicable); or do not exceed size requirements for the subparts.
Blowing Stills (associated with SN-825)	40 C.F.R. 60, Subpart UU	Constructed prior to November 18, 1980.
Pumps, compressors, pressure relief devices, sampling connections, systems, open-	40 C.F.R. 61, Subpart J	There are no affected facilities in benzene service (greater than 10% benzene by weight).

Source No.	Regulation	Description
ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems		
Storage Vessels	40 C.F.R. 61, Subpart Y	None of the storage vessels contain benzene products.
Cooling Tower	40 C.F.R. 63, Subpart Q	Cooling towers have not operated with chromium-based water treatment chemicals on or after September 8, 1994.

Consent Decree (CIV. No. 03-1028) Requirements

The following conditions are required to be added to this permit by Paragraph 24 of the Consent Decree (CIV. No. 03-1028) reached between Lion Oil, the US EPA, and ADEQ. In many instances, these conditions are restatements of requirements which appear elsewhere in the Specific and/or Plantwide Conditions of this permit.

PW 20. The heaters and boilers at Lion Oil are affected facilities, as that term is used in 40 C.F.R. Part 60 Subparts A and J, and are subject to and comply with the requirements of NSPS Subpart A and J. If there is a revision to NSPS Subpart J that excludes either certain fuel gas combustion devices or fuel gas streams from Subpart J, then that exemption shall comply to this condition as well.

PW 21. The permittee shall not burn fuel oil in any combustion unit except under the following circumstances. Fuel Oil shall mean any liquid fossil fuel with a sulfur content of greater than 0.05% by weight. Torch Oil shall mean FCCU feedstock or light cycle oil that is combusted in the FCCU regenerator to assist in starting up or restarting the FCCU.
 [§19.304 of Regulation 19 and 40 C.F.R. § 60.11(d)]

- a. The permittee is permitted to burn torch oil in the FCCU regenerator during FCCU start-ups;
- b. Lion Oil is permitted to burn Fuel Oil in combustion units after the establishment of FCCU NO_x emission limits pursuant to Paragraph 11.E. of the Consent Decree, provided that emissions from any such combustion units are routed through the FCCU Wet Gas Scrubber and Lion Oil demonstrates, with the approval of EPA, that the NO_x emission limits established therein and the SO₂ emissions limits set forth in Paragraph 12.B. of this Consent Decree will continue to be met.

- c. During periods of natural gas curtailment where the permittee shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur by wt.).
- PW 22. The Sulfur Recovery Plant (SN-844) is subject to and required to comply with all applicable provisions of 40 C.F.R. § 60 (NSPS) Subparts A and J. [§19.304 of Regulation 19 and 40 C.F.R. § 60 Subparts A and J]
- PW 23. The permittee shall continue to route all sulfur pit emissions from the sulfur recovery plant (SN-844) such that sulfur pit emissions to the atmosphere are either eliminated or are included and monitored as part of the applicable sulfur recovery plant tail gas emissions that meet the NSPS Subpart J limit for SO₂: a 12-hour rolling average of 250 ppmvd SO₂ corrected to 0% oxygen. [§19.304 of Regulation 19 and 40 C.F.R. § 60.104(a)(2)]
- PW 24. The permittee shall comply with the Preventive Maintenance and Operation Plan for the Sulfur Recovery Plant, including any modifications thereto, at all times, including periods of start up, shut down, and malfunction. [§19.304 of Regulation 19 and 40 C.F.R. § 60.11(d)]
- PW 25. The permittee shall comply with the following requirements as they relate to tail gas incidents where tail gas is combusted in a thermal incinerator and results in excess emissions of 500 pounds or more of SO₂ emissions in any 24-hour period. Only those time periods which are in excess of an SO₂ concentration of 250 ppm (rolling 12-hour average) shall be used to determine the amount of excess SO₂ emissions from the incinerator. Lion Oil shall use engineering judgment and/or other monitoring data during periods in which the SO₂ CEM system has exceeded the range of the instrument or is out of service.. [§19.304 of Regulation 19 and 40 C.F.R. § 60.11(d)]
- a. For tail gas incidents the investigative and corrective action procedures shall be applied to TGU shutdowns, bypasses of a TGU, unscheduled shutdowns of a sulfur recovery plant, or other miscellaneous unscheduled sulfur recovery plant events which result in a tail gas incident.
 - b. The permittee shall investigate the root cause and all contributing causes of all tail gas incidents. The permittee shall take reasonable steps to correct the conditions that have caused or contributed to such incidents, and to minimize such incidents. The permittee shall evaluate whether tail gas incidents are due to malfunctions.
- PW 26. The permittee is prohibited from using the emissions reductions that result from the installation and operation of the controls required by the Consent Decree (CIV. No. 03-1028) (“CD Emissions Reductions”) for the purpose of emissions netting or emissions offsets, while still allowing the permittee to use a fraction of the CD emissions reductions if: (1) the emission unit for which the permittee seeks to use the CD emissions reductions are modified or constructed for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (2) the emissions from those modified or newly-constructed units are below the levels outlined in paragraph 27.C.ii of the Consent Decree (CIV. No. 03-1028) prior to the commencement of operations of the emissions units for which the permittee seeks to use the CD emissions reductions.

- a. **General Prohibition** – The permittee shall not generate or use any NO_x, SO₂, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the Consent Decree (CIV. No. 03-1028) as netting reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review (NSR) permit or permit proceeding.
- b. **Exception to General Prohibition:**
 - i. Utilization of the exception set forth in paragraph 27.C.ii of the Consent Decree (CIV. No. 03-1028) to the general prohibition against the generation or utilization of CD emissions reductions set forth in paragraph 27.B of the Consent Decree (CIV. No. 03-1028) is subject to the following conditions:
 - 1. Under no circumstances shall the permittee use CD emissions reductions for netting and/or offsets prior to the time that actual CD emissions reductions have occurred.
 - 2. CD emissions reductions may only be used at the El Dorado refinery that generated them.
 - 3. The CD emissions reductions provisions of the Consent Decree (CIV. No. 03-1028) are for the purposes of the Consent Decree (CIV. No. 03-1028) only and neither the permittee nor any other entity may use CD emissions reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein.
 - 4. The permittee shall remain subject to all federal and state regulations applicable to the PSD, major non-attainment, and/or minor NSR permitting processes.
 - ii. Notwithstanding the general prohibition set forth in Paragraph 27.B of the Consent Decree (CIV. No. 03-1028), the permittee may use 10 tons per year of NO_x, 10 tpy of PM, and 35 tpy of SO₂ from the CD emissions reductions as credits or offsets in any PSD, major non-attainment, and/or minor NSR permit or permit proceeding occurring after the date of lodging of the Consent Decree (CIV. No. 03-1028) (March 11, 2003), provided that the new or modified emissions unit: (1) is being constructed or modified for the purposes of compliance with Tier II gasoline or low-sulfur diesel requirements; and (2) has a federally enforceable permit that reflects:
 - 1. For heaters and boilers, that next-generation ultra low-NO_x burners are installed and the limit is established pursuant to Paragraph 16.D of the Consent Decree (CIV. No. 03-1028).
 - 2. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot (dscf) of fuel gas or 20 ppmvd SO₂ corrected to 0% oxygen both on a 3-hour rolling average.

3. For heaters and boilers, no liquid or solid fuel firing authorization.
4. For the FCCU, a limit of 20 ppmvd NO_x or less corrected to 0% oxygen on a 365-day rolling average basis.
5. For the FCCU, a limit of 25 ppmvd SO₂ corrected to 0% oxygen on a 365-day rolling average basis.
6. For SRP's, NSPS Subpart J emission limits.

PW 27. None of the conditions of this permit are intended to prohibit the permittee from seeking to: (1) utilize or generate emissions credits or reductions from refinery units that are covered by the Consent Decree (CIV. No. 03-1028) to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in the Consent Decree (CIV. No. 03-1028) for these refinery units and the more stringent emissions limitations that the permittee may elect to accept for those refinery units in a permitting process; or (2) utilize or generate or generate emission credits or reductions on refinery units that are not covered by the Consent Decree (CIV. No. 03-1028).

PW 28. By no later than December 31, 2004, Lion Oil shall install a VDU overhead recovery system on the Vacuum Distillation Tower pursuant to the terms and conditions in its October 9, 2002 submission to the Agencies. Lion has complied with this requirement by routing emissions to the Flare Gas Recovery system.

PW 29. The permittee shall submit a modification to incorporate the provisions of regulations specifically addressed in the Compliance Plan and Schedule of this permit six months before the compliance date specified in the Compliance Plan and Schedule.

PW 30. The permittee must meet the **notification requirements** in § 63.7545 according to the schedule in § 63.7545 and in subpart A of 40 C.F.R. Part 63. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart. [Reg. 19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 31. At all times, the permittee must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [Reg. 19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 32. The permittee shall for SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821a, SN-821b, SN-821c, SN-828, SN-842, SN-850, SN-857, SN-860, SN-861 East, SN-861 West, and SN-862 conduct annual tune ups. Burners part of SN-832 with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. [Reg. 19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 33. The permittee must conduct an annual or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each 5-year tune-up specified in

§ 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up.
[Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

PW 34. The permittee shall for SN-803, SN-804, SN-805, SN-805N, SN-806, SN-808, SN-810, SN-811, SN-812, SN-813a, SN-814, SN-821a, SN-821b, SN-821c, SN-828, SN-832, SN-842, SN-850, SN-857, SN-860, SN-861 East, SN-861 West, and SN-862 have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:

- a. A visual inspection of the boiler or process heater system.
- b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
- c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
- d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
- e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
- f. A list of cost-effective energy conservation measures that are within the facility's control.
- g. A list of the energy savings potential of the energy conservation measures identified.
- h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated May 27, 2011.

Description	Category
Acid Fume Scrubbers	A-13
Lime Silo with Baghouse	A-13
Asphalt Protective Coating Baghouse	A-13
Up to 250 A-2 Tanks	A-2
Up to 18 A-3 Tanks	A-3
3 Waste Oil Tanks	A-3
Caustic Tanks which contain no VOCs	A-4
Surface coating, painting, dipping, or spraying that emit no VOC or HAPs	A-9

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 70.6(b)(2)]
2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 C.F.R. § 70.6(a)(2) and Reg.26.701(B)]
3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Reg.26.406]
4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 C.F.R. § 70.6(a)(1)(ii) and Reg.26.701(A)(2)]
5. The permittee must maintain the following records of monitoring information as required by this permit.
 - a. The date, place as defined in this permit, and time of sampling or measurements;
 - b. The date(s) analyses performed;
 - c. The company or entity performing the analyses;
 - d. The analytical techniques or methods used;
 - e. The results of such analyses; and
 - f. The operating conditions existing at the time of sampling or measurement.

[40 C.F.R. § 70.6(a)(3)(ii)(A) and Reg.26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 C.F.R. § 70.6(a)(3)(ii)(B) and Reg.26.701(C)(2)(b)]
7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Reg.26.2 must certify all required reports. The permittee will send the reports to the address below:

Arkansas Department of Environmental Quality
Air Division
ATTN: Compliance Inspector Supervisor
5301 Northshore Drive
North Little Rock, AR 72118-5317

[40 C.F.R. § 70.6(a)(3)(iii)(A) and Reg.26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.
 - a. For all upset conditions (as defined in Reg.19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:
 - i. The facility name and location;
 - ii. The process unit or emission source deviating from the permit limit;
 - iii. The permit limit, including the identification of pollutants, from which deviation occurs;
 - iv. The date and time the deviation started;
 - v. The duration of the deviation;
 - vi. The emissions during the deviation;
 - vii. The probable cause of such deviations;
 - viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and

ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

- b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Reg.19.601, Reg.19.602, Reg.26.701(C)(3)(b), and 40 C.F.R. § 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Reg.26.701(E), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. § 7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 C.F.R. § 70.6(a)(6)(i) and Reg.26.701(F)(1)]
11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 C.F.R. § 70.6(a)(6)(ii) and Reg.26.701(F)(2)]
12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 C.F.R. § 70.6(a)(6)(iii) and Reg.26.701(F)(3)]
13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and Reg.26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and Reg.26.701(F)(5)]
15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 C.F.R. § 70.6(a)(7) and Reg.26.701(G)]
16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 C.F.R. § 70.6(a)(8) and Reg.26.701(H)]
17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 C.F.R. § 70.6(a)(9)(i) and Reg.26.701(I)(1)]
18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and Reg.26.702(A) and (B)]
19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Reg.26.2. [40 C.F.R. § 70.6(c)(1) and Reg.26.703(A)]
20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and Reg.26.703(B)]
 - a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
 - b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
 - c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
 - d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and Reg.26.703(E)(3)]
 - a. The identification of each term or condition of the permit that is the basis of the certification;
 - b. The compliance status;
 - c. Whether compliance was continuous or intermittent;
 - d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
 - e. Such other facts as the Department may require elsewhere in this permit or by § 114(a)(3) and § 504(b) of the Act.
22. Nothing in this permit will alter or affect the following: [Reg.26.704(C)]
 - a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
 - b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
 - c. The applicable requirements of the acid rain program, consistent with § 408(a) of the Act; or
 - d. The ability of EPA to obtain information from a source pursuant to § 114 of the Act.
23. This permit authorizes only those pollutant emitting activities addressed in this permit. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:
 - a. Such an extension does not violate a federal requirement;
 - b. The permittee demonstrates the need for the extension; and
 - c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Reg.18.314(A), Reg.19.416(A), Reg.26.1013(A), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:
- a. Such a request does not violate a federal requirement;
 - b. Such a request is temporary in nature;
 - c. Such a request will not result in a condition of air pollution;
 - d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
 - e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
 - f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Reg.18.314(B), Reg.19.416(B), Reg.26.1013(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:
- a. The request does not violate a federal requirement;
 - b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
 - c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Reg.18.314(C), Reg.19.416(C), Reg.26.1013(C), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

Appendix A

Arkansas Department of Environmental Quality



CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised September 2013

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.
- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the Relative Accuracy Test Audit (RATA), Relative Accuracy Audit (RAA), or Cylinder Gas Audit (CGA) which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

- A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.
- B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.
- C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.
- D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval, the excess zero and span drifts measured must be quantified and recorded.
- E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.
- F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.
- G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.
- H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
- I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ

CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

**** All CEMS/COMS shall comply with this section.**

- A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.
- B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 business days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.
- C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.
- D. Each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter.
- E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.
- F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.
- G. Quarterly reports shall be used by the Department to determine compliance with the permit.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

** Only CEMS/COMS required by ADEQ permit for reasons other than Part 60, 63 or 75 shall comply with this section.

- A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.
- B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.
- C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:
 - 1. Calibration of CEMS/COMS
 - a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
 - 2. Calibration drift determination and adjustment of CEMS/COMS
 - a. Out-of-control period determination
 - b. Steps of corrective action
 - 3. Preventive maintenance of CEMS/COMS
 - a. CEMS/COMS information
 - 1) Manufacture
 - 2) Model number
 - 3) Serial number
 - b. Scheduled activities (check list)
 - c. Spare part inventory
 - 4. Data recording, calculations, and reporting
 - 5. Accuracy audit procedures including sampling and analysis methods
 - 6. Program of corrective action for malfunctioning CEMS/COMS
- D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three

quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O ₂ & CO ₂)	> 1.0 % O ₂ or CO ₂
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O ₂ & CO ₂)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O ₂ & CO ₂)	> 15% of the three run average or > 7.5 % of the applicable standard

- F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of the successful daily zero or span drift or completion of the successful CGA, RAA or RATA.
- G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

Appendix B

Environmental Protection Agency

§ 60.40b

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (b)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[74 FR 5083, Jan. 28, 2009, as amended at 77 FR 9459, Feb. 16, 2012]

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but

on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_x) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_x standards under this subpart and to the sulfur dioxide (SO₂) standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_x standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the NO_x standards under this subpart and the PM and SO₂ standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO₂ standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_x and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

§ 60.41b

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

- (1) Section 60.44b(f).
- (2) Section 60.44b(g).
- (3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, § 60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO₂ and NO_x standards under this subpart and the PM standards under subpart BB.

40 CFR Ch. I (7–1–14 Edition)

(m) Temporary boilers are not subject to this subpart.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO₂) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO₂ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices

where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work

performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m³ (70,000 Btu/hr-ft³).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m³ (70,000 Btu/hr-ft³) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper,

wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO₂ emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary

boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO₂ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid

§ 60.42b

40 CFR Ch. I (7–1–14 Edition)

material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.42b Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s = SO₂ emission limit, in ng/J or lb/MMBtu heat input;
 K_a = 520 ng/J (or 1.2 lb/MMBtu);
 K_b = 340 ng/J (or 0.80 lb/MMBtu);
 H_a = Heat input from the combustion of coal, in J (MMBtu); and
 H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected fa-

cility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO₂ emissions, shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 50 percent of the potential SO₂ emission rate (50 percent reduction) and that contain SO₂ in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO₂ emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil

of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO₂ emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO₂ emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO₂ emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO₂ control) are equal to or

§ 60.43b

40 CFR Ch. I (7–1–14 Edition)

less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO₂ control system is not being operated because of malfunction or maintenance of the SO₂ control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine SO₂ emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in § 60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO₂ emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with

any other fuels with a potential SO₂ emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO₂ emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a non-continental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement

Environmental Protection Agency

§ 60.43b

limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO₂ emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO₂ emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual

capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type

solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be com-

pleted under § 60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either

Environmental Protection Agency

§ 60.44b

fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except

a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.44b Standard for nitrogen oxides (NO_x).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO₂) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO ₂) heat input	
	ng/J	lb/MMBtu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_x emission limit (expressed as NO₂), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

§ 60.44b

40 CFR Ch. I (7–1–14 Edition)

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO₂ emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_x emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_x emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_x emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the

emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (1)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (1)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_x emission limit will be established at the NO_x emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_x emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_x emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_x emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_x emission limits required by this section. The owner or operator of the af-

ected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_x emission limits of this section. The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (1)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30

§ 60.45b

40 CFR Ch. I (7–1–14 Edition)

weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_x emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO₂) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_x emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of

270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO₂ emission standards in § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO₂ control system maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO₂ emission rate (% P_s) and the SO₂ emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO₂ standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

Environmental Protection Agency

§ 60.45b

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO₂ emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100 \left(1 - \frac{\%R_g}{100} \right) \left(1 - \frac{\%R_f}{100} \right)$$

Where:

%P_s = Potential SO₂ emission rate, percent;
 %R_g = SO₂ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and
 %R_f = SO₂ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO₂ emission rate (E_{ho}^o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^o). The E_{ho}^o is computed using the following formula:

$$E_{ho}^o = \frac{E_{ho} - E_w (1 - X_k)}{X_k}$$

Where:

E_{ho}^o = Adjusted hourly SO₂ emission rate, ng/J (lb/MMBtu);
 E_{ho} = Hourly SO₂ emission rate, ng/J (lb/MMBtu);
 E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and
 X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO₂ emission rate (%P_s), an adjusted %R_g (%R_g^o) is computed from the adjusted E_{ao}^o from paragraph (b)(3)(i) of this section and an adjusted average SO₂ inlet rate (E_{ai}^o) using the following formula:

$$\%R_g^o = 100 \left(1.0 - \frac{E_{ao}^o}{E_{ai}^o} \right)$$

To compute E_{ai}^o, an adjusted hourly SO₂ inlet rate (E_{hi}^o) is used. The E_{hi}^o is computed using the following formula:

$$E_{hi}^o = \frac{E_{hi} - E_w (1 - X_k)}{X_k}$$

Where:

E_{hi}^o = Adjusted hourly SO₂ inlet rate, ng/J (lb/MMBtu); and
 E_{hi} = Hourly SO₂ inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine %P_s following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO₂ emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO₂ emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the SO₂ emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO₂ for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating condi-

tions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the SO₂ emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO₂ for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO₂ are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P_s and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid SO₂ emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating %P_s and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO₂ control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate %P_s or E_s under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO₂ standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_x emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_x emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O₂) or CO₂ sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O₂ or CO₂ measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_x required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_x under § 60.48(b).

(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed

§ 60.46b

40 CFR Ch. I (7–1–14 Edition)

or is required to be completed in § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_x emission standards in § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_x standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards.

A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by § 60.44b(a)(4) or § 60.44b(1) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b} \right) (E_{sg} - E_g) \quad (\text{Eq. 1})$$

Where:

E = Emissions rate of NO_x from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O₂ concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

Environmental Protection Agency

§ 60.46b

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring NO_x and O₂ and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_x emission standards under § 60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_x emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures in § 60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial start-up of the affected facility, as specified

under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and per-

formance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012; 79 FR 11249, Feb. 27, 2014]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO₂ standards in § 60.42b shall install, calibrate, maintain, and operate

CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO₂ and either O₂ or CO₂ concentrations shall both be monitored at the inlet and outlet of the SO₂ control device. If the owner or operator has installed and certified SO₂ and O₂ or CO₂ CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO₂ concentration data and CO₂ (or O₂) data are collected simultaneously; and

(2) In addition to meeting the applicable SO₂ and CO₂ (or O₂) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. SO₂ and CO₂ (or O₂) data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO₂ data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate, or

(2) Measuring SO₂ according to Method 6B of appendix A of this part at the inlet or outlet to the SO₂ control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO₂ emission rate, E_p, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods

and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO₂ emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average SO₂ emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO₂ CEMS at the inlet to the SO₂ control device is 125 percent of the maximum estimated hourly potential SO₂ emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO₂ control device is 50 percent of the maximum estimated hourly potential SO₂ emissions of the fuel combusted. Alternatively, SO₂ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO₂ and O₂ monitors and for SO₂ and NO_x monitors with span values greater than or equal to 100 ppm, the daily calibration error

test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO₂ and O₂ monitors and for SO₂ and NO_x monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO₂ and NO_x span values less than or equal to 30 ppm; and

(iii) For SO₂, CO₂, and O₂ monitoring systems and for NO_x emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3

of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO₂ (regardless of the SO₂ emission level during the RATA), and for NO_x when the average NO_x emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 79 FR 11249, Feb. 27, 2014]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-

7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS

“Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_x and O₂ (or CO₂) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

Environmental Protection Agency

§ 60.48b

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_x is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_x span values shall be determined as follows:

Fuel	Span values for NO _x (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_x span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_x standards in § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring NO_x emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO₂ or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO₂ or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such

that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems

within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided

Environmental Protection Agency

§ 60.49b

that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO₂ emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO₂. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of

the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂, PM, and/or NO_x emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_x standard in § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in § 60.48b(g)(2) and the records to be maintained in § 60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the

ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O₂ level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall main-

tain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with

Environmental Protection Agency

§ 60.49b

the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_x standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_x emission rates (expressed as NO₂) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_x standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO₂ standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period,

ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO₂ control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO₂ emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(1) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and

the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO₂ emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks,

Environmental Protection Agency

§ 60.49b

CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO₂ standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, %R_f) is used to determine the overall percent reduction (*i.e.*, %R_o) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, %R_f) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provi-

sions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any NO_x emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_x emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification

in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_x standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b(i).

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_x burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Environmental Protection Agency

§ 60.49b

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The require-

ments of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_x technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO₂ and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted,

§ 60.40c

the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_x.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product/waste are simultaneously combusted, the NO_x emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_x.* (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the moni-

40 CFR Ch. I (7–1–14 Edition)

toring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary

Appendix C

§ 60.40c

the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_x.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product/waste are simultaneously combusted, the NO_x emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_x.* (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in § 60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the moni-

40 CFR Ch. I (7–1–14 Edition)

toring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary

combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO₂ standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum

design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.*, the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any appli-

cable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO₂ emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of

an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO₂ emissions limit or the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first,

Environmental Protection Agency

§ 60.42c

no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate or numerical SO₂ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO₂ emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas

§ 60.43c

40 CFR Ch. I (7–1–14 Edition)

turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005,

may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO₂ emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and § 60.8(b),

performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

§ 60.44c

40 CFR Ch. I (7–1–14 Edition)

(1) An adjusted E_{ho} (E_{hoO}) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{aoO}). The E_{hoO} is computed using the following formula:

$$E_{hoO} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E_{hoO} = Adjusted E_{ho} , ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100 \left(1 - \frac{\%R_g}{100} \right) \left(1 - \frac{\%R_f}{100} \right)$$

Where:

$\%P_s$ = Potential SO_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_{gO}$) is computed from E_{aoO} from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{aiO}) using the following formula:

$$\%R_{gO} = 100 \left(1 - \frac{E_{ao}^o}{E_{ai}^o} \right)$$

Where:

$\%R_{gO}$ = Adjusted $\%R_g$, in percent;

E_{aoO} = Adjusted E_{ao} , ng/J (lb/MMBtu); and

E_{aiO} = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{aiO} , an adjusted hourly SO_2 inlet rate (E_{hiO}) is used. The E_{hiO} is computed using the following formula:

$$E_{hiO} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

E_{hiO} = Adjusted E_{hi} , ng/J (lb/MMBtu);

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial

tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO₂ standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P_s and E_{h_o} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P_s or E_{h_o} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the

§ 60.45c

40 CFR Ch. I (7–1–14 Edition)

sample gas in the probe and filter holder shall be monitored and maintained at $160 \pm 14^\circ\text{C}$ ($320 \pm 25^\circ\text{F}$).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and (iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or

5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial start-up of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic

Environmental Protection Agency

§ 60.46c

averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html) or other com-

patible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO₂ emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO₂ concentrations and either O₂ or CO₂ concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content

and heat content according to the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the

stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of

an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be

completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or op-

erator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO₂ or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly

CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures

§ 60.48c

40 CFR Ch. I (7–1–14 Edition)

and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any sub-

sequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

Environmental Protection Agency

§ 60.48c

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant,

at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO₂ standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain

records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(c) Any facility covered by subpart Cb, Eb, AAAA, or BBBB of this part is not covered by this subpart.

(d) Any facility covered by an EPA approved State section 111(d)/129 plan implementing subpart Cb or BBBB of this part is not covered by this subpart.

Appendix D

Subpart J—Standards of Performance for Petroleum Refineries

§60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) through (e) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from §60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

(e) Owners or operators may choose to comply with the applicable provisions of subpart Ja of this part to satisfy the requirements of this subpart for an affected facility.

(f) For purposes of this subpart, under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component

replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) *Process gas* means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) *Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) *Fuel gas combustion device* means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide (H₂S), carbonyl sulfide (COS) and carbon disulfide (CS₂).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) *Fluid catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) *Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A “valid hour” is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989; 73 FR 35865, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

§60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

§60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce SO_2 emissions to the atmosphere by 90 percent or maintain SO_2 emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce SO_2 emission, maintain sulfur oxides emissions calculated as SO_2 to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in §60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

§60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to §60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to §60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in §10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to §60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess.

(i) The span values for this monitor are 50 ppm SO₂ and 25 percent oxygen (O₂).

(ii) The SO₂ monitoring level equivalent to the H₂S standard under §60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO₂ emissions into the atmosphere from each of the combustion devices.

(4) Instead of the SO₂ monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to §60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H₂S.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned.

(iii) The performance evaluations for this H₂S monitor under §60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under §60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under §60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to §60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO₂ and 25 percent O₂.

(ii) The performance evaluations for this SO₂ monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to §60.104(a)(2)(ii), an instrument for continuously monitoring and recording the

concentration of reduced sulfur and O₂ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent O₂.

(ii) The performance evaluations for this reduced sulfur (and O₂) monitor under §60.13(c) shall use Performance Specification 5 of appendix B of this part (and Performance Specification 3 of appendix B of this part for the O₂ analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O₂ concentrations below 0.25 percent during the performance specification test, the O₂ concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O₂ monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO₂. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO₂ and 25 percent O₂.

(ii) For reporting purposes, the SO₂ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ (and O₂) monitor under §60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases at both the inlet and outlet of the SO₂ control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under §60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential SO₂ emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential SO₂ emission concentration entering the control device.

(ii) The performance evaluations for these SO₂ monitors under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of SO₂ in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under §60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential SO₂ emission concentration of the control device.

(ii) The performance evaluations for this SO₂ monitor under §60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O₂) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with §60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the §60.13(e) performance evaluation.

(ii) Appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with §60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in §60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1) that is not specifically exempted in §60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

- (i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system, and the affected fuel gas combustion device(s) to be considered;
- (ii) A statement that there are no crossover or entry points for sour gas (high H₂S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);
- (iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;
- (iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377-86 (incorporated by reference—see §60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when $1 \leq N \leq 10$, where N = number of pump strokes, to test the applicant fuel gas stream for H₂S; and
- (v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H₂S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting H₂S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H₂S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information

following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H₂S monitoring using daily stain sampling to demonstrate compliance using length-of stain tubes with a maximum span between 200 and 400 ppmv inclusive when $1 \leq N \leq 5$, where N = number of pump strokes. The owner or operator must begin monitoring according to the requirements in paragraph (a)(1) or (2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H₂S concentration limit.

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to §60.102, §60.103, or §60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under §60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

NOTE: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity*. All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under §60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide*. All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion*. (i) All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under §60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants.* (i) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under §60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO₂) as measured by the reduced sulfur continuous monitoring system under §60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under §60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008; 80 FR 75229, Dec. 1, 2015]

§60.106 Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in §60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = \frac{c_s Q_{sd}}{KR_c}$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

c_s = Concentration of PM, g/dscm (gr/dscf).

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

R_c = Coke burn-off rate, Mg/hr (ton/hr) coke.

K = Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the

sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate (R_c) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO/2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} (\%O_{oxy})$$

Where:

R_c = Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

Q_r = Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

Q_a = Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

Q_{oxy} = Volumetric flow rate of O_2 enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$ = Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%CO$ = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$ = O_2 concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the fluid catalytic cracking unit regenerator, percent by volume (dry basis).

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)].

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_r).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine CO_2 , CO, and O_2 concentrations.

(4) Method 9 and the procedures of §60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in §60.102(b) as follows:

(1) The allowable emission rate (E_s) of PM shall be computed for each run using the following equation:

$$E_s = F + A (H/R_c)$$

Where:

E_s = Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F = Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, 43 g/GJ (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, GJ/hr (million Btu/hr).

R_c = Coke burn-off rate, Mg coke/hr (ton coke/hr).

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in §60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)(1) The owner or operator shall determine compliance with the H_2S standard in §60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

(i) For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H_2S may necessitate sampling for longer periods of time.

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by §60.105(a)(3), compliance with §60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the SO₂ and the H₂S and reduced sulfur standards in §60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO₂ concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m² (53.8 ft²) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is 5.00 m² or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H₂S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO₂ equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the SO₂ equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the SO₂, reduced sulfur and H₂S, or moisture samples. The SO₂, reduced

sulfur, and H₂S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under §60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with §60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in §60.13(h). These calculations are made using the emission data collected under §60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R_{SO_2} = 100(C_{SO_2}(i) - C_{SO_2}(o)) / C_{SO_2}(i)$$

where:

R_{SO_2} = 7-day average sulfur dioxide emission reduction, percent

$C_{SO_2}(i)$ = sulfur dioxide emission concentration determined in §60.106(h)(2) at the inlet to the add-on control device, ppmv

$C_{SO_2}(o)$ = sulfur dioxide emission concentration determined in §60.106(h)(2) at the outlet to the add-on control device, ppmv

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, O₂-free basis, shall be calculated using the procedures outlined in §60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C_{\text{adj}} = C_{\text{meas}} [20.9_c / (20.9 - \%O_2)]$$

where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm

20.9_c = 20.9 percent oxygen–0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

$\%O_2$ = oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with §60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in §60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which

auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_x credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8-3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (C_{so_x}).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{so_x} = C_{so_x} Q_{sd} / K$$

Where:

E_{so_x} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

C_{so_x} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K = 1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{so_x} = (E_{so_x} / R_c)$$

Where:

R_{so_x} = Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

E_{so_x} = Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

R_c = Coke burn-off rate, Mg/hr (ton/hr).

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with §60.104(b)(2), as provided in §60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with §60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129-64, 78, or 95, ASTM D1552-83 or 95, ASTM D2622-87, 94, or 98, or ASTM D1266-87, 91, or 98. (These methods are incorporated by reference: see §60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^n \frac{S_i Q_i}{Q_f}$$

where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

Q_f = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the “ith” sampling location.

Q_i = volumetric flow rate of fresh feed stream for the “ith” sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in §60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10869, Mar. 15, 1978; 51 FR 42842, Nov. 26, 1986; 52 FR 20392, June 1, 1987; 53 FR 41333, Oct. 21, 1988; 54 FR 34028, Aug. 17, 1989; 55 FR 40176, Oct. 2, 1990; 56 FR 4176, Feb. 4, 1991; 65 FR 61754, Oct. 17, 2000; 71 FR 55127, Sept. 21, 2006; 73 FR 35867, June 24, 2008; 77 FR 56463, Sep. 12, 2012]

§60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.104(b) shall notify the Administrator of the specific provisions of §60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by §60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of §60.104(b), then the Administrator shall be notified by the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to §60.104(b) shall record and maintain the following information:

(1) If subject to §60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to §60.105(a)(13) and §60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to §60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if §60.106(i)(12) applies.

(3) If subject to §60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to §60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O₂-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under §60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under §60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under §60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under §60.106(i). The average emission rate shall be determined using the procedures specified under §60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with §60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under §60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in §60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

(iv) A description of the corrective action taken, if any.

(4) If subject to §60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to §60.104(b)(2), for each day in which a Method 8 sample result required by §60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to §60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by §60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1), if an owner or operator determines that one of the exemptions listed in §60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in

§60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(f) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(g) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000; 73 FR 35867, June 24, 2008]

§60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in §60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under §60.104(b). Performance tests conducted for the purpose of determining compliance under §60.104(b) shall be conducted according to the applicable procedures specified under §60.106.

(b) Owners or operators who seek to comply with §60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with §60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under §60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to §60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under §60.106. In the event that a sample collected under §60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to §60.104(b) who has demonstrated compliance with one of the provisions of §60.104(b) but a later date seeks to comply with another of the provisions of §60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of §60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by §60.107(f).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999; 73 FR 35867, June 24, 2008]

§60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

(1) Section 60.105(a)(13)(iii),

(2) Section 60.106(i)(12).

[54 FR 34031, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990]

Appendix E

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or

SOURCE: 73 FR 35867, June 24, 2008, unless otherwise noted.

§60.100a Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which either commence construction, modification or reconstruction after May 14, 2007, or elect to comply with the provisions of this subpart in lieu of complying with the provisions in subpart J of this part. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a “delayed coking unit” defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a “delayed coking unit” defined as follows: a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a “delayed coking unit” as defined in §60.101a.

(c) For all affected facilities other than flares, the provisions in §60.14 regarding modification apply. As provided in §60.14(f), the special provisions set forth under this subpart shall supersede the provisions in §60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.*, for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.*, addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) For purposes of this subpart, under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015]

§60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in §60.2 and in this section.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading

operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.*, the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.104a.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases from an affected facility in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system*. The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.*, balanced draft system) is considered to be a *forced draft process heater*.

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with

a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.*, asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO₂) and recycling the SO₂ to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO₂ to a sulfur product.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery*.

Primary flare means the first flare in a cascaded flare system.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.*, flares without water seals do not use *purge gas*).

Reduced sulfur compounds means hydrogen sulfide (H_2S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H_2S and either recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H_2S to a sulfur product.

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

Sour water means water that contains sulfur compounds (usually H_2S) at concentrations of 10 parts per million by weight or more.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. A *sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 78 FR 76756, Dec. 19, 2013; 80 FR 75230, Dec. 1, 2015]

§60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 gram per kilogram (g/kg) (1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 g/kg (1 lb/1,000 lb) coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_x) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO₂) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to §60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in §60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under §60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O₂) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O₂ concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3) of this section, each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraph (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a design production capacity greater than 20 long tons per day (LTD), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator shall comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) as a flow rate weighted average for a group of release points from the

sulfur recovery plant provided that flow is monitored as specified in §60.106a(a)(7); if flow is not monitored as specified in §60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity greater than 20 long LTD and a reduction control system not followed by incineration, the owner or operator shall also comply with the H₂S emission limit in paragraph (f)(1)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases containing SO₂ into the atmosphere in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O₂ concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO₂ emissions limit is 250 ppmv (dry basis) at zero percent excess air.

$$E_{LS} = k_1 \times (-0.038 \times (\%O_2)^2 + 11.53 \times \%O_2 + 25.6) \quad (\text{Eq. 1})$$

Where:

E_{LS} = Emission limit for large sulfur recovery plant, ppmv (as SO₂, dry basis at zero percent excess air);

k₁ = Constant factor for emission limit conversion: k₁ = 1 for converting to the SO₂ limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and k₁ = 1.2 for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

%O₂ = O₂ concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used for the Claus burner or if the owner or operator elects not to monitor O₂ concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for %O₂.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 300 ppmv calculated as ppmv SO₂ (dry basis) at 0-percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing hydrogen sulfide (H₂S) in excess of 10 ppmv calculated as ppmv SO₂ (dry basis) at zero percent excess air.

(2) For a sulfur recovery plant with a design production capacity of 20 LTD or less, the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator may comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in §60.106a(a)(7); if flow is not monitored as specified in §60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity of 20 LTD or less and a reduction control system not followed by incineration, the owner or operator shall also comply with the H₂S emission limit in paragraph (f)(2)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing SO₂ in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O₂ concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO₂ emission limit is 2,500 ppmv (dry basis) at zero percent excess air.

$$E_{ss} = k_1 \times (-0.38 \times (\%O_2)^2 + 115.3 \times \%O_2 + 256) \quad (\text{Eq. 2})$$

Where:

E_{ss} = Emission limit for small sulfur recovery plant, ppmv (as SO₂, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to the SO₂ limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

%O₂ = O₂ concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used in the Claus burner or if the owner or operator elects not to monitor O₂ concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for %O₂.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 3,000 ppmv calculated as ppmv SO₂ (dry basis) at zero percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing H_2S in excess of 100 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(3) The emission limits in paragraphs (f)(1) and (2) of this section shall not apply during periods of maintenance of the sulfur pit, which shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section. For CO boilers or furnaces that are part of a fluid catalytic cracking unit or fluid coking unit affected facility, the owner or operator shall comply with the fuel gas concentration limit in paragraph (g)(1)(ii) for all fuel gas streams combusted in these units.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_x in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{NO_x} = \frac{0.06 Q_{gas} HHV_{gas} + 0.35 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad (Eq. 3)$$

Where:

ER_{NO_x} = Daily allowable average emission rate of NO_x , lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NO_x} = \frac{0.11 Q_{gas} HHV_{gas} + 0.40 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad (\text{Eq. 4})$$

Where:

ER_{NO_x} = Daily allowable average emission rate of NO_x , lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_x emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_x emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (e.g., ultra-low NO_x burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.*, operating in turndown mode). The site-specific NO_x emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_x emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_x burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in §60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_x emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_x emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(4) The approval process for a request for a facility-specific NO_x emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_x emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_x burner designs and other combustion modifications considered for reducing NO_x emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_x emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_x emissions limit will be established at the NO_x emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56466, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015; 81 FR 45240, July 13, 2016]

§60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (e.g., air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (e.g., staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H₂S or flow monitoring and why (e.g., natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H₂S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.*, gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.*, separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.*, excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) through (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in §60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO₂ emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m³) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in §60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in §60.102a(g)(1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO₂ emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO₂ or reduced sulfur concentration was equal to the applicable emissions limit in §60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in §60.108a(c)(6) and reported as described in §60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in §60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in §60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refinerynsps@epa.gov.

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

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

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(iii) Any equivalent 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.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

[77 FR 56467, Sep. 12, 2012]

§60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in §60.102a and conduct a performance test for each flare to demonstrate initial compliance with the H₂S concentration requirement in §60.103a(h) according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in §60.105a(b), to use bag leak detectors according to the requirements in §60.105a(c), or to use COMS according to the requirements in §60.105a(e) shall conduct a PM performance test at least annually (*i.e.*, once per calendar year, with an interval of at least 8 months but no more than 16 months between annual tests) and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A-1 through A-8 or other methods as specified in this section, except as provided in §60.8(b).

(d) The owner or operator shall determine compliance with the PM, NO_x, SO₂, and CO emissions limits in §60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 5, 5B, or 5F of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in §63.102a(b)(1). Use Method 5 or 5B of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in §63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \quad (\text{Eq. 5})$$

Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\frac{\%CO}{2} + \%CO_2 + \%O_2 \right) + K_3 Q_{oxy} (\%O_{oxy})$$

(Eq. 6)

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide (CO_2) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%CO$ = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A-1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in §60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%O_{xy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. 7})$$

Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%CO$ = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with §60.105a(h)(3), assume $\%CO$ to be zero;

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A-4 to part 60 for moisture content and for the concentration of SO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_x calculated as nitrogen dioxide (NO₂); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(7) Method 10, 10A, or 10B of appendix A-4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NO_x, SO₂ and CO pollutant concentrations to 0-percent excess air or 0-percent O₂ using Equation 8 of this section:

$$C_{adj} = C_{meas} \left[\frac{20.9}{20.9 - \%O_2} \right] \quad (\text{Eq. 8})$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O₂, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O₂–0.0 percent O₂ (defined O₂ correction basis), percent;

20.9 = O₂ concentration in air, percent; and

%O₂ = O₂ concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 9 of this section:

$$\text{Opacity Limit} = \text{Opacity}_{st} \times \left(\frac{1 \text{ lb} / 1,000 \text{ lb coke burn}}{\text{PMEMR}_{st}} \right) \quad (\text{Eq. 9})$$

Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

Opacity_{st} = Hourly average opacity measured during the source test, percent; and

PMEMR_{st} = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to §60.105a(h)(3) and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O₂ concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O₂ concentrations as the average of the average temperature and O₂ concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO₂ emissions limits for sulfur recovery plants in §60.102a(f)(1)(i) and (f)(2)(i) and the reduced sulfur compounds and H₂S emissions limits for sulfur recovery plants in §60.102a(f)(1)(ii), (f)(1)(iii), (f)(2)(ii), and (f)(2)(iii) using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO₂ concentration. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(5) Method 15 or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 to determine the reduced sulfur compounds and H₂S concentrations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H₂S concentration after correcting for moisture and O₂ as the arithmetic average of the H₂S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO₂ equivalent for each run after correcting for moisture and O₂ as the arithmetic average of the SO₂ equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O₂ or 0-percent excess air.

(6) If oxygen or oxygen-enriched air is used in the Claus burner and either Equation 1 or 2 of this subpart is used to determine the applicable emissions limit, determine the average O₂ concentration of the air/oxygen mixture supplied to the Claus burner, in percent by volume (dry basis), for the performance test using all hourly average O₂ concentrations determined during the test runs using the procedures in §60.106a(a)(5) or (6).

(i) The owner or operator shall determine compliance with the SO₂ and NO_x emissions limits in §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60;

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO₂ concentration. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under §60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_x calculated as NO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in §60.107a(c)(6) or (d)(8), the owner or operator shall establish the O₂ operating limit or O₂ operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O₂ operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O₂ concentration for each test run of a valid test.

(D) Calculate the O₂ operating limit as the average O₂ concentration of the three test runs from a valid test.

(ii) If an O₂ operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O₂ operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired,

primarily oil fired, and equally co-fired, *i.e.*, approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.*, when the process heater is firing at 50 percent or less of the rated heat capacity). If O₂ operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O₂ concentration for each test run of a valid test.

(E) Calculate the O₂ operating limit for each operating range as the average O₂ concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O₂ operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O₂ operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_x limit in terms of lb/MMBtu as provided in §60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O₂ limit, as provided in §60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O₂ or 0- percent excess air.

(j) The owner or operator shall determine compliance with the applicable H₂S emissions limit in §60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in §60.103a(h) for a flare according to the following test methods and procedures:

(1)—(3) [Reserved]

(4) EPA Method 11, 15 or 15A of appendix A-5 to part 60 or EPA Method 16 of appendix A-6 to part 60 for determining the H₂S concentration for affected facilities using an H₂S monitor as specified in §60.107a(a)(2). The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

(i) For Method 11 of appendix A-5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.

(ii) For Method 15 of appendix A-5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A-5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under §60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56470, Sep. 12, 2012; 80 FR 75231, Dec. 1, 2015]

§60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

(a) *FCCU and FCU subject to PM emissions limit.* Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in §60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in §60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary current to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check. Faulty (*e.g.*, leaking or plugged) air or water lines must be repaired within 12 hours of identification of an abnormal pressure reading.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in §60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO₂, O₂ (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels. A CO monitor is not required for determining coke burn-off rate when no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with paragraph (h)(3) of this section.

(i) The owner or operator shall install, operate, and maintain each CO₂ and O₂ monitor according to Performance Specification 3 of appendix B to this part.

(ii) The owner or operator shall conduct performance evaluations of each CO₂ and O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3 of appendix A-3 to this part for conducting the relative accuracy evaluations.

(iii) If a CO monitor is required, the owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. If this CO monitor also serves to demonstrate compliance with the CO emissions limit in §60.102a(b)(4), the span value for this instrument is 1,000 ppm; otherwise, the span value for this instrument should be set at approximately 2 times the typical CO concentration expected in the FCCU or FCU flue gas prior to any emission control or energy recovery system that burns auxiliary fuels.

(iv) If a CO monitor is required, the owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 of appendix B to this part. The owner or operator shall use Method 10, 10A, or 10B of appendix A-3 to this part for conducting the relative accuracy evaluations.

(v) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to this part, including quarterly accuracy determinations for CO₂ and CO monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS)*. An owner or operator subject to the PM concentration emission limit (in gr/dscf) in §60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in §60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of appendix A-3 to part 60 or Method 17 of appendix A-6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each O₂ monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O₂ monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in §60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to §60.13(c) and Performance Specification 1 of appendix B to part 60.

(f) *FCCU and FCU subject to NO_x limit.* Each owner or operator subject to the NO_x emissions limit in §60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each NO_x monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_x monitor is 200 ppmv NO_x.

(2) The owner or operator shall conduct performance evaluations of each NO_x monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas

Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each NO_x and O₂ monitor, including quarterly accuracy determinations for NO_x monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO₂ limit.* The owner or operator subject to the SO₂ emissions limit in §60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO₂ monitor according to Performance Specification 2 of appendix B to part 60. The span value of this SO₂ monitor is 200 ppmv SO₂.

(2) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each SO₂ and O₂ monitor, including quarterly accuracy determinations for SO₂ monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in §60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. The span value for this instrument is 1,000 ppmv CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to this part. The span value shall be 100 ppmv CO instead of 1,000 ppmv, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppmv CO, whichever is greater. For instruments that are identical to Method 10 of appendix A-4 to this part and employ the sample conditioning system of Method 10A of appendix A-4 to this part, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to this part may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O₂ monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O₂ concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O₂ concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in §60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to paragraph (b)(1) of this section, all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under paragraph (b)(1), fall below the levels established during the performance test. If the alternative to pressure drop CPMS is used for the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, each day in which abnormal pressure readings are not corrected within 12 hours of identification.

(2) If a bag leak detection system is used according to paragraph (c) of this section, each day in which the cause of an alarm is not alleviated within the time period specified in paragraph (c)(3) of this section.

(3) If a PM CEMS is used according to §60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under §60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(4) If a COMS is used according to §60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under §60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(5) All rolling 7-day periods during which the average concentration of NO_x as measured by the NO_x CEMS under §60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(6) All rolling 7-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS under §60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS exceeds 25 ppmv.

(7) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under paragraph (h) of this section exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O₂ concentration as measured by the continuous monitoring systems under paragraph (h)(4) of this section fall below the operating limits established during the performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012; 80 FR 75232, Dec. 1, 2015]

§60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in §60.102a(f)(1) or §60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO₂ emission limit in §60.102a(f)(1)(i) or §60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span value for the SO₂ monitor is two times the applicable SO₂ emission limit at the highest O₂ concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each SO₂ CEMS according to Performance Specification 2 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6 or 6C of appendix A-4 to part 60 and Method 3 or 3A of appendix A-2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6.

(iv) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(2) For sulfur recovery plants that are subject to the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur

compounds and O₂ emissions into the atmosphere. The reduced sulfur compounds emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span value for the reduced sulfur compounds monitor is two times the applicable reduced sulfur compounds emission limit as SO₂ at the highest O₂ concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur compounds CEMS according to Performance Specification 5 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur compounds monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60.

(v) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur compounds monitor required in paragraph (a)(2) of this section, the owner or operator may install, calibrate, operate, and maintain an instrument using an air or O₂ dilution and oxidation system to convert any reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO₂. The monitor must include an O₂ monitor for correcting the data for excess O₂.

(i) The span value for this monitor is two times the applicable reduced sulfur compounds emission limit as SO₂ at the highest O₂ concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall conduct performance evaluations of each SO₂ monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the

relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO₂ monitor, annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(4) For sulfur recovery plants that are subject to the H₂S emission limit in §60.102a(f)(1)(iii) or (f)(2)(iii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H₂S, and O₂ emissions into the atmosphere. The H₂S emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span value for this monitor is two times the applicable H₂S emission limit.

(ii) The owner or operator shall install, operate, and maintain each H₂S CEMS according to Performance Specification 7 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use Methods 11 or 15 of appendix A-5 to this part or Method 16 of appendix A-6 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part.

(iv) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the

relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(5) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner and that elects to monitor O₂ concentration of the air/oxygen mixture supplied to the Claus burner, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the O₂ concentration of the air/oxygen mixture supplied to the Claus burner in order to determine the allowable emissions limit.

(i) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to this part.

(ii) The span value for the O₂ monitor shall be 100 percent.

(iii) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(iv) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O₂ monitor, and daily calibration drift determinations.

(v) The owner or operator shall use the hourly average O₂ concentration from this monitor for use in Equation 1 or 2 of §60.102a(f), as applicable, for each hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.*, the rolling 12-hour average).

(6) As an alternative to the O₂ monitor required in paragraph (a)(5) of this section, the owner or operator may install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of ambient air and oxygen-enriched gas supplied to the Claus burner and calculate the hourly average O₂ concentration of the air/oxygen mixture used in the Claus burner as specified in paragraphs (a)(6)(i) through (iv) of this section in order to determine the allowable emissions limit as specified in paragraphs (a)(6)(v) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ± 5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure and, for ambient air flow monitor, moisture content, and is able to record dry flow in standard conditions (as defined in §60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall use 20.9 percent as the oxygen content of the ambient air.

(iii) The owner or operator shall use product specifications (*e.g.*, as reported in material safety data sheets) for percent oxygen for purchased oxygen. For oxygen produced onsite, the percent oxygen shall be determined by periodic measurements or process knowledge.

(iv) The owner or operator shall calculate the hourly average O_2 concentration of the air/oxygen mixture used in the Claus burner using Equation 10 of this section:

$$\%O_2 = \left(\frac{20.9 \times Q_{air} + \%O_{2,oxy} \times Q_{oxy}}{Q_{air} + Q_{oxy}} \right) \quad (\text{Eq. 10})$$

Where:

$\%O_2$ = O_2 concentration of the air/oxygen mixture used in the Claus burner, percent by volume (dry basis);

20.9 = O_2 concentration in air, percent dry basis;

Q_{air} = Volumetric flow rate of ambient air used in the Claus burner, dscfm;

$\%O_{2,oxy}$ = O_2 concentration in the enriched oxygen stream, percent dry basis; and

Q_{oxy} = Volumetric flow rate of enriched oxygen stream used in the Claus burner, dscfm.

(v) The owner or operator shall use the hourly average O_2 concentration determined using Equation 8 of §60.104a(d)(8) for use in Equation 1 or 2 of §60.102a(f), as applicable, for each

hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.*, the rolling 12-hour average).

(7) Owners or operators of a sulfur recovery plant that elects to comply with the SO₂ emission limit in §60.102a(f)(1)(i) or (f)(2)(i) or the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant rather than for each process train or release point individually shall install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of each release point within the group of release points from the sulfur recovery plant as specified in paragraphs (a)(7)(i) through (iv) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ±5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure, and moisture content, and is able to record dry flow in standard conditions (as defined in §60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall correct the flow to 0 percent excess air using Equation 11 of this section:

$$Q_{adj} = Q_{meas} \left[\frac{(20.9 - \%O_2)}{20.9} \right] \quad (\text{Eq. 11})$$

Where:

Q_{adj} = Volumetric flow rate adjusted to 0 percent excess air, dry standard cubic feet per minute (dscfm);

Q_{meas} = Volumetric flow rate measured by the flow meter corrected to dry standard conditions, dscfm;

$20.9_c = 20.9 \text{ percent O}_2 - 0.0 \text{ percent O}_2 \text{ (defined O}_2 \text{ correction basis), percent;}$

$20.9 = \text{O}_2 \text{ concentration in air, percent; and}$

$\% \text{O}_2 = \text{O}_2 \text{ concentration measured on a dry basis, percent.}$

(iii) The owner or operator shall calculate the flow weighted average SO₂ or reduced sulfur compounds concentration for each hour using Equation 12 of this section:

$$C_{ave} = \frac{\sum_{n=1}^N (C_n \times Q_{adj,n})}{\sum_{n=1}^N Q_{adj,n}} \quad (\text{Eq. 12})$$

Where:

C_{ave} = Flow weighted average concentration of the pollutant, ppmv (dry basis, zero percent excess air). The pollutant is either SO₂ (if complying with the SO₂ emission limit in §60.102a(f)(1)(i) or (f)(2)(i)) or reduced sulfur compounds (if complying with the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii));

N = Number of release points within the group of release points from the sulfur recovery plant for which emissions averaging is elected;

C_n = Pollutant concentration in the n^{th} release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, ppmv (dry basis, zero percent excess air);

$Q_{adj,n}$ = Volumetric flow rate of the n^{th} release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, dry standard cubic feet per minute (dscfm, adjusted to 0 percent excess air).

(iv) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner, the owner or operator shall use Equation 10 of this section and the hourly emission limits determined in paragraph (a)(5)(v) or (a)(6)(v) of this section in-place of the pollutant concentration to determine the flow weighted average hourly emission limit for each hour. The allowable emission limit shall be calculated as the arithmetic average of 12 contiguous 1-hour averages (*i.e.*, the rolling 12-hour average).

(b) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in §60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section.

NOTE: Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

- (1) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this section exceeds the applicable emission limit (dry basis, zero percent excess air); or
- (2) All 12-hour periods during which the average concentration of reduced sulfur compounds (as SO₂) as measured by the reduced sulfur compounds continuous monitoring system required under paragraph (a)(2) or (3) of this section exceeds the applicable emission limit; or
- (3) All 12-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(4) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

[73 FR 35867, June 24, 2008, as amended at 80 FR 75232, Dec. 1, 2015]

§60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to SO₂ or H₂S limit and flares subject to H₂S concentration requirements.* The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the SO₂ emission limits in §60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the H₂S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H₂S concentration requirement in §60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO₂ emissions limits in §60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of SO₂ emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air.

(i) The owner or operator shall install, operate, and maintain each SO₂ monitor according to Performance Specification 2 of appendix B to this part. The span value for the SO₂ monitor is 50 ppmv SO₂.

(ii) The owner or operator shall conduct performance evaluations for the SO₂ monitor according to the requirements of §60.13(c) and Performance Specification 2 of appendix B to this part. The owner or operator shall use Methods 6, 6A, or 6C of appendix A-4 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to this part. Samples taken by Method 6 of appendix A-4 to this part shall be taken at a flow rate of

approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppmv, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value for the O₂ monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the O₂ monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60, including quarterly accuracy determinations for SO₂ monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO₂ emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H₂S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H₂S concentration requirement in §60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.

(ii) The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.

(iv) Fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the

concentration of H₂S in the fuel gas being burned in the respective fuel gas combustion devices or flares.

(v) The owner or operator of a flare subject to §60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H₂S concentration requirement in §60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H₂S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in §60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to §60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) Exemption from H₂S monitoring requirements for low-sulfur fuel gas streams. The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H₂S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H₂S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv H₂S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377-86 (incorporated by reference—see §60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when $1 \leq N \leq 10$, where N = number of pump strokes, to test the applicant fuel gas stream for H₂S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H₂S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of

typical operating conditions affecting H₂S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H₂S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H₂S monitoring using daily stain sampling to demonstrate compliance using length-of-stain tubes with a maximum span between 200 and 400 ppmv inclusive when $1 \leq N \leq 5$, where N = number of pump strokes. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable, but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H₂S concentration limit. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H₂S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

(c) *Process heaters complying with the NO_x concentration-based limit.* The owner or operator of a process heater subject to the NO_x emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a(g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A) or (g)(2)(iv)(A) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this section, except as provided in paragraph (c)(6) of this section. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, the owner or operator shall install, operate and maintain each NO_x monitor according to Performance Specification 2 of appendix B

to part 60. The span value of this NO_x monitor must be between 2 and 3 times the applicable emissions limit, inclusive.

(2) The owner or operator shall conduct performance evaluations of each NO_x monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O₂ monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each NO_x and O₂ monitor, including quarterly accuracy determinations for NO_x monitors, annual accuracy determinations for O₂ monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_x emissions (*i.e.*, low-NO_x burners, ultra-low-NO_x burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O₂ operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O₂ operating curve is used (*i.e.*, if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_x heating value-based or mass-based limit.* The owner or operator of a process heater subject to the NO_x emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a(g)(2)(i)(B) or (g)(2)(ii)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or

operator of a co-fired process heater subject to the NO_x emissions limit in §60.102a(g)(2) and electing to comply with the heating value-based limit in §60.102a(g)(2)(iii)(B) or (g)(2)(iv)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere according to the monitoring requirements in paragraph (d)(1) of this section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, the owner or operator shall install, operate and maintain each NO_x monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O₂ monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 13 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \quad (\text{Eq. 13})$$

Where:

F_d = F factor on dry basis at 0% excess air, dscf/MMBtu.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

- (i) EPA Method 18 of appendix A-6 to part 60;
- (ii) ASTM D1945-03 (Reapproved 2010)(incorporated by reference-see §60.17);
- (iii) ASTM D1946-90 (Reapproved 2006)(incorporated by reference-see §60.17);
- (iv) ASTM D6420-99 (Reapproved 2004)(incorporated by reference-see §60.17);
- (v) GPA 2261-00 (incorporated by reference-see §60.17); or
- (vi) ASTM UOP539-97 (incorporated by reference-see §60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.*, 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.*, 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in §60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

- (i) EPA Method 2, 2A, 2B, 2C or 2D of appendix A-2 to part 60;
- (ii) ASME MFC-3M-2004 (incorporated by reference-see §60.17);
- (iii) ANSI/ASME MFC-4M-1986 (Reaffirmed 2008) (incorporated by reference-see §60.17);
- (iv) ASME MFC-6M-1998 (Reaffirmed 2005) (incorporated by reference-see §60.17);
- (v) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006) (incorporated by reference-see §60.17);
- (vi) ASME MFC-11M-2006 (incorporated by reference-see §60.17);
- (vii) ASME MFC-14M-2003 (incorporated by reference-see §60.17);
- (viii) ASME MFC-18M-2001 (incorporated by reference-see §60.17);
- (ix) AGA Report No. 3, Part 1 (incorporated by reference-see §60.17);

- (x) AGA Report No. 3, Part 2 (incorporated by reference-see §60.17);
- (xi) AGA Report No. 11 (incorporated by reference-see §60.17);
- (xii) AGA Report No. 7 (incorporated by reference-see §60.17); and
- (xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see §60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in §60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

- (i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.*, “fluids”);
- (ii) ANSI/ASME-MFC-5M-1985 (Reaffirmed 2006) (incorporated by reference-see §60.17);
- (iii) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006) (incorporated by reference-see §60.17);
- (iv) ASME MFC-16-2007 (incorporated by reference-see §60.17);
- (v) ASME MFC-22-2007 (incorporated by reference-see §60.17); or
- (vi) ISO 8316 (incorporated by reference-see §60.17).

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (ix) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the affected process heater(s). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

- (i) ASTM D240-02 (Reapproved 2007) (incorporated by reference-see §60.17).
- (ii) ASTM D1826-94 (Reapproved 2003) (incorporated by reference-see §60.17).
- (iii) ASTM D1945-03 (Reapproved 2010) (incorporated by reference-see §60.17).
- (iv) ASTM D1946-90 (Reapproved 2006) (incorporated by reference-see §60.17).
- (v) ASTM D3588-98 (Reapproved 2003) (incorporated by reference-see §60.17).

(vi) ASTM D4809-06 (incorporated by reference-see §60.17).

(vii) ASTM D4891-89 (Reapproved 2006) (incorporated by reference-see §60.17).

(viii) GPA 2172-09 (incorporated by reference-see §60.17).

(ix) Any of the methods specified in section 2.2.7 of appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_x emissions (*i.e.*, low-NO_x burners or ultra-low NO_x burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O₂ operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O₂ operating curve is used (*i.e.*, if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument or instruments for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of appendix B to part 60. The span value should be

determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of appendix A-5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each total reduced sulfur monitor.

(2) *H₂S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument or instruments for continuously monitoring and recording the concentration of H₂S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

(i) The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H₂S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each H₂S monitor according to the requirements in §60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use EPA Method 11, 15 or 15A of appendix A-5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.

(iv) In the first 10 operating days after the date the flare must begin to comply with §60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of appendix A-5 to part 60, EPA Method 16A of appendix A-6 to part 60, ASTM Method D4468-85 (Reapproved 2006) (incorporated by reference—see §60.17) or ASTM Method D5504-08 (incorporated by reference—see §60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H₂S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H₂S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H₂S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 14 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \quad (Eq. 14)$$

Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

Ratio_{Avg} = 10-day average total sulfur-to-H₂S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H₂S concentration ratios used to develop the 10-day average total sulfur-to-H₂S concentration ratio, unitless.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H₂S

ratio by the daily average H₂S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H₂S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(3) *SO₂ monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of SO₂ from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements in paragraph (d)(7) of this section, and calculate the total sulfur content (as SO₂) in the fuel gas using Equation 15 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \quad (\text{Eq. 15})$$

Where:

TS_{FG} = Total sulfur concentration, as SO₂, in the fuel gas, ppmv.

C_{SO₂} = Concentration of SO₂ in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO₂ emissions in the event of a discharge that may trigger a root cause analysis under §60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H₂S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO₂ emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(ii) Use a flow sensor meeting an accuracy requirement of ± 20 percent of the flow rate at velocities ranging from 0.1 to 1 feet per second and an accuracy of ± 5 percent of the flow rate for velocities greater than 1 feet per second.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in §60.2) over one-minute averages.

(iv) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(v) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for

any such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to §60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

(2) Minimize or eliminate pulsating pressure, vibration and internal and external corrosion.

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

(5) Conduct calibration checks any time the pressure sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.*, the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under §60.108a(d)(5) ("reportable pressure exceedances") in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the

monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) and flares subject to the concentration requirement in §60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO₂ or H₂S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO₂ emission limits in §60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H₂S concentration limits in §60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H₂S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H₂S exceeds 60 ppmv.

(2) *H₂S concentration limits for flares.* (i) Each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H₂S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_x limits for fuel gas combustion devices.* Each rolling 30-day period during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) For a natural draft process heater, 40 ppmv and, if monitored according to §60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to §60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_x limit in §60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

(iv) The site-specific limit determined by the Administrator under §60.102a(i).

(4) *Daily NO_x limits for fuel gas combustion devices.* Each day during which the concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (d) of this section exceeds the daily average emissions limit calculated using Equation 3 in §60.102a(g)(2)(iii)(B) or Equation 4 in §60.102a(g)(2)(iv)(B).

(5) *Daily O₂ limits for fuel gas combustion devices.* Each day during which the concentration of O₂ as measured by the O₂ continuous monitoring system required under paragraph (c)(6) or (d)(8) of this section exceeds the O₂ operating limit or operating curve determined during the most recent biennial performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012; 80 FR 75235, Dec. 1, 2015]

§60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section.

(b) Each owner or operator subject to an emissions limitation in §60.102a shall notify the Administrator of the specific monitoring provisions of §§60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in §60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in §60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by §60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan.

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in §60.105a(c).

(3) Records of bag leak detection system alarms and actions according to §60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in §60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in §60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in §60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) Records of discharges greater than 500 lb SO₂ in any 24-hour period from any affected flare, discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by §60.103a(c). If the monitoring alternative provided in §60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in §60.103a(a)(3)(vii)(C). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

(i) A description of the discharge.

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices, but are not allowed for flares, except for those complying with the alternative monitoring requirements in §60.107a(g).

(iv) For each discharge greater than 500 lb SO₂ in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H₂S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in §60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO₂ discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO₂ in any 24-hour period from any affected flare or discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H₂S and SO₂ released into the

atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO₂. For fuel gas combustion devices, assume 99-percent conversion of H₂S to SO₂.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) The root cause analysis and corrective action analysis conducted as required in §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §60.103a(e).

(x) For any corrective action analysis for which corrective actions are required in §60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with §60.107a(e)(2) for a flare, records of the H₂S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H₂S ratios, the calculated 10-day average total sulfur-to-H₂S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H₂S ratio.

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under §60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to §60.107a(e) and (f) within 180 days following the fifth discharge.

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56479, Sep. 12, 2012]

§60.109a Delegation of authority.

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

(1) Approval of a major change to test methods under §60.8(b). A “major change to test method” is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under §60.13(i). A “major change to monitoring” is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under §60.7(b) through (f). A “major change to recordkeeping/reporting” is defined in 40 CFR 63.90.

(4) Approval of an application for an alternative means of emission limitation under §60.103a(j) of this subpart.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56480, Sep. 12, 2012]

Table 1 to Subpart Ja of Part 60—Molar Exhaust Volumes and Molar Heat Content of Fuel Gas Constituents

Constituent	MEV^a dscf/mol	MHC^b Btu/mol
Methane (CH ₄)	7.29	842
Ethane (C ₂ H ₆)	12.96	1,475
Hydrogen (H ₂)	1.61	269

Ethene (C ₂ H ₄)	11.34	1,335
Propane (C ₃ H ₈)	18.62	2,100
Propene (C ₃ H ₆)	17.02	1,947
Butane (C ₄ H ₁₀)	24.30	2,717
Butene (C ₄ H ₈)	22.69	2,558
Inerts	0.85	0

^aMEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

^bMHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

[77 FR 56480, Sep. 12, 2012]

Appendix F

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

§60.110a Applicability and designation of affected facility.

(a) *Affected facility.* Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a storage capacity greater than 151,416 liters (40,000 gallons) that is used to store petroleum liquids for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

(c) *Alternative means of compliance—*(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112a through 60.114a for storage vessels that are subject to this subpart that store petroleum liquids that, as stored, have a maximum true vapor pressure equal to or greater than 10.3 kPa (1.5 psia). Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (c)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78275, Dec. 14, 2000]

§60.111a Definitions.

In addition to the terms and their definitions listed in the Act and subpart A of this part the following definitions apply in this subpart:

(a) *Storage vessel* means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396-78, 89, 90, 92, 96, or 98, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM D2880-78 or 96, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM D2880-78 or 96, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM D975-78, 96, or 98a. (These three methods are incorporated by reference—see §60.17.)

(c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

(f) *True vapor pressure* means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from External Floating-Roof Tanks, Second Edition, February 1980 (incorporated by reference—see §60.17).

(g) *Reid vapor pressure* is the absolute vapor pressure of volatile crude oil and nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323-82 or 94 (incorporated by reference—see §60.17).

(h) *Liquid-mounted seal* means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.

(i) *Metallic shoe seal* includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(j) *Vapor-mounted seal* means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.

(k) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

[45 FR 23379, Apr. 4, 1980, as amended at 48 FR 3737, Jan. 27, 1983; 52 FR 11429, Apr. 8, 1987; 65 FR 61756, Oct. 17, 2000]

§60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in paragraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114a.

(b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

[45 FR 23379, Apr. 4, 1980, as amended at 45 FR 83229, Dec. 18, 1980]

§60.113a Testing and procedures.

(a) Except as provided in §60.8(b) compliance with the standard prescribed in §60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in §60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)(B) of this section.

(D) Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by paragraph (a)(1)(ii) of this section and the calculation required by paragraph (a)(1)(iii) of this section.

(E) If either the seal gap calculated in accord with paragraph (a)(1)(iii) of this section or the measured maximum seal gap exceeds the limitations specified by §60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of §60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of §60.112a.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a $\frac{1}{8}$ " diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in §60.112a(a)(1)(i) and §60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

(2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

(i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.

(ii) The manufacturer's design specifications and estimated emission reduction capability of the system.

(iii) The operation and maintenance plan for the system.

(iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[45 FR 23379, Apr. 4, 1980, as amended at 52 FR 11429, Apr. 8, 1987]

§60.114a Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112a, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

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

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112a.

(e) The primary vapor-mounted seal in the “Volume-Maximizing Seal” manufactured by R.F.I. Services Corporation is approved as equivalent to the vapor-mounted seal required by §60.112a(a)(1)(i) and must meet the gap criteria specified in §60.112a(a)(1)(i)(B). There shall be no gaps between the tank wall and any secondary seal used in conjunction with the primary seal in the “Volume-Maximizing Seal”.

[52 FR 11429, Apr. 8, 1987]

§60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) The owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of §60.112a(a)(3) and (b), or a closed vent system and control device meeting the specifications of 40 CFR 65.42(b)(4), (b)(5), or (c).

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78275, Dec. 14, 2000]

Appendix G

Environmental Protection Agency

§ 60.110b

§ 60.114a Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112a, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

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

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112a.

(e) The primary vapor-mounted seal in the "Volume-Maximizing Seal" manufactured by R.F.I. Services Corporation is approved as equivalent to the vapor-mounted seal required by § 60.112a(a)(1)(i) and must meet the gap criteria specified in § 60.112a(a)(1)(i)(B). There shall be no gaps between the tank wall and any secondary seal used in conjunction with the primary seal in the "Volume-Maximizing Seal".

[52 FR 11429, Apr. 8, 1987]

§ 60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that

liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) The owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112a(a)(3) and (b), or a closed vent system and control device meeting the specifications of 40 CFR 65.42(b)(4), (b)(5), or (c).

[45 FR 23379, Apr. 4, 1980, as amended at 65 FR 78275, Dec. 14, 2000]

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

SOURCE: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility

§ 60.111b

40 CFR Ch. I (7–1–14 Edition)

to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m³) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m³ used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a

maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be

limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see § 60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see § 60.17);

(4) Any other method approved by the Administrator.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see § 60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m³ but less

than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely

cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or great-

er. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§ 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in § 60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in § 60.112b(a)

§ 60.113b

40 CFR Ch. I (7–1–14 Edition)

shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of § 60.112b.

(a) After installing the control equipment required to meet § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet § 60.112b(a)(2)

Environmental Protection Agency

§ 60.113b

(external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements

listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of § 60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in § 60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level con-

ditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

Environmental Protection Agency

§ 60.115b

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

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in § 60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed

and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 61.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

§ 60.116b

40 CFR Ch. I (7–1–14 Edition)

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or

equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the

Environmental Protection Agency

§ 60.121

actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in § 60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17); or

(ii) ASTM D323-82 or 94 (incorporated by reference—see § 60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of § 60.112b or with emissions reductions equipment as specified

in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Subpart L—Standards of Performance for Secondary Lead Smelters

§ 60.120 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: Pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

[42 FR 37937, July 25, 1977]

§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Reverberatory furnace* includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) *Secondary lead smelter* means any facility producing lead from a leadbearing scrap material by smelting to the metallic form.

(c) *Lead* means elemental lead or alloys in which the predominant component is lead.

Appendix H

Subpart UU—Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

§60.470 Applicability and designation of affected facilities.

(a) The affected facilities to which this subpart applies are each saturator and each mineral handling and storage facility at asphalt roofing plants; and each asphalt storage tank and each blowing still at asphalt processing plants, petroleum refineries, and asphalt roofing plants.

(b) Any saturator or mineral handling and storage facility under paragraph (a) of this section that commences construction or modification after November 18, 1980, is subject to the requirements of this subpart. Any asphalt storage tank or blowing still that processes and/or stores asphalt used for roofing only or for roofing and other purposes, and that commences construction or modification after November 18, 1980, is subject to the requirements of this subpart.

Any asphalt storage tank or blowing still that processes and/or stores only nonroofing asphalts and that commences construction or modification after May 26, 1981, is subject to the requirements of this subpart.

§60.471 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Afterburner (A/B) means an exhaust gas incinerator used to control emissions of particulate matter.

Asphalt processing means the storage and blowing of asphalt.

Asphalt processing plant means a plant which blows asphalt for use in the manufacture of asphalt products.

Asphalt roofing plant means a plant which produces asphalt roofing products (shingles, roll roofing, siding, or saturated felt).

Asphalt storage tank means any tank used to store asphalt at asphalt roofing plants, petroleum refineries, and asphalt processing plants. Storage tanks containing cutback asphalts (asphalts diluted with solvents to reduce viscosity for low temperature applications) and emulsified asphalts (asphalts dispersed in water with an emulsifying agent) are not subject to this regulation.

Blowing still means the equipment in which air is blown through asphalt flux to change the softening point and penetration rate.

Catalyst means a substance which, when added to asphalt flux in a blowing still, alters the penetrating-softening point relationship or increases the rate of oxidation of the flux.

Coating blow means the process in which air is blown through hot asphalt flux to produce coating asphalt. The coating blow starts when the air is turned on and stops when the air is turned off.

Electrostatic precipitator (ESP) means an air pollution control device in which solid or liquid particulates in a gas stream are charged as they pass through an electric field and precipitated on a collection surface.

High velocity air filter (HVAF) means an air pollution control filtration device for the removal of sticky, oily, or liquid aerosol particulate matter from exhaust gas streams.

Mineral handling and storage facility means the areas in asphalt roofing plants in which minerals are unloaded from a carrier, the conveyor transfer points between the carrier and the storage silos, and the storage silos.

Saturator means the equipment in which asphalt is applied to felt to make asphalt roofing products. The term saturator includes the saturator, wet looper, and coater.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§60.472 Standards for particulate matter.

(a) On and after the date on which §60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any saturator:

(1) Particulate matter in excess of:

(i) 0.04 kg/Mg (0.08 lb/ton) of asphalt shingle or mineral-surfaced roll roofing produced, or

(ii) 0.4 kg/Mg (0.8 lb/ton) of saturated felt or smooth-surfaced roll roofing produced;

(2) Exhaust gases with opacity greater than 20 percent; and

(3) Any visible emissions from a saturator capture system for more than 20 percent of any period of consecutive valid observations totaling 60 minutes. Saturators that were constructed before November 18, 1980, and that have not been reconstructed since that date and that become subject to these standards through modification are exempt from the visible emissions standard. Saturators that have been newly constructed or reconstructed since November 18, 1980 are subject to the visible emissions standard.

(b) On and after the date on which §60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blowing still:

(1) Particulate matter in excess of 0.67 kg/Mg (1.3 lb/ton) of asphalt charged to the still when a catalyst is added to the still; and

(2) Particulate matter in excess of 0.71 kg/Mg (1.4 lb/ton) of asphalt charged to the still when a catalyst is added to the still and when No. 6 fuel oil is fired in the afterburner; and

(3) Particulate matter in excess of 0.60 kg/Mg (1.2 lb/ton) of asphalt charged to the still during blowing without a catalyst; and

(4) Particulate matter in excess of 0.64 kg/Mg (1.3 lb/ton) of asphalt charged to the still during blowing without a catalyst and when No. 6 fuel oil is fired in the afterburner; and

(5) Exhaust gases with an opacity greater than 0 percent unless an opacity limit for the blowing still when fuel oil is used to fire the afterburner has been established by the Administrator in accordance with the procedures in §60.474(g).

(c) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any asphalt storage tank exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The control device shall not be bypassed during this 15-minute period. If, however, the emissions from any asphalt storage tank(s) are ducted to a control device for a saturator, the combined emissions shall meet the emission limit contained in paragraph (a) of this section during the time the saturator control device is operating. At any other time the asphalt storage tank(s) must meet the opacity limit specified above for storage tanks.

(d) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any mineral handling and storage facility emissions with opacity greater than 1 percent.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000; 79 FR 11250, Feb. 27, 2014]

§60.473 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart, and using either an electrostatic precipitator or a high velocity air filter to meet the emission limit in §60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature of the gas at the inlet of the control device. The temperature monitoring instrument shall have an accuracy of $\pm 15^{\circ}\text{C}$ ($\pm 25^{\circ}\text{F}$) over its range.

(b) The owner or operator subject to the provisions of this subpart and using an afterburner to meet the emission limit in §60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature in the combustion zone of the afterburner. The monitoring instrument shall have an accuracy of $\pm 10^{\circ}\text{C}$ ($\pm 18^{\circ}\text{F}$) over its range.

(c) An owner or operator subject to the provisions of this subpart and using a control device not mentioned in paragraphs (a) or (b) of this section shall provide to the Administrator information describing the operation of the control device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may require continuous monitoring and will determine the process parameters to be monitored.

(d) The industry is exempted from the quarterly reports required under §60.7(c). The owner/operator is required to record and report the operating temperature of the control device during the performance test and, as required by §60.7(d), maintain a file of the temperature monitoring results for at least two years.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§60.474 Test methods and procedures.

(a) For saturators, the owner or operator shall conduct performance tests required in §60.8 as follows:

(1) If the final product is shingle or mineral-surfaced roll roofing, the tests shall be conducted while 106.6-kg (235-lb) shingle is being produced.

(2) If the final product is saturated felt or smooth-surfaced roll roofing, the tests shall be conducted while 6.8-kg (15-lb) felt is being produced.

(3) If the final product is fiberglass shingle, the test shall be conducted while a nominal 100-kg (220-lb) shingle is being produced.

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

(c) The owner or operator shall determine compliance with the particulate matter standards in §60.472 as follows:

(1) The emission rate (E) of particulate matter shall be computed for each run using the following equation:

$$E = (c_s Q_{sd}) / (PK)$$

where:

E = emission rate of particulate matter, kg/Mg (lb/ton).

c_s = concentration of particulate matter, g/dscm (gr/dscf).

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

P = asphalt roofing production rate or asphalt charging rate, Mg/hr (ton/hr).

K = conversion factor, 1000 g/kg [7000 (gr/lb)].

(2) Method 5A shall be used to determine the particulate matter concentration (c_s) and volumetric flow rate (Q_{sd}) of the effluent gas. For a saturator, the sampling time and sample volume for each run shall be at least 120 minutes and 3.00 dscm (106 dscf), and for the blowing still, at least 90 minutes or the duration of the coating blow or non-coating blow, whichever is greater, and 2.25 dscm (79.4 dscf).

(3) For the saturator, the asphalt roofing production rate (P) for each run shall be determined as follows: The amount of asphalt roofing produced on the shingle or saturated felt process lines shall be obtained by direct measurement. The asphalt roofing production rate is the amount produced divided by the time taken for the run.

(4) For the blowing still, the asphalt charging rate (P) shall be computed for each run using the following equation:

$$P = (Vd)/(K' \theta)$$

where:

P = asphalt charging rate to blowing still, Mg/hr (ton/hr).

V = volume of asphalt charged, m³ (ft³).

d = density of asphalt, kg/m³ (lb/ft³).

K' = conversion factor, 1000 kg/Mg (2000 lb/ton).

θ = duration of test run, hr.

(i) The volume (V) of asphalt charged shall be measured by any means accurate to within 10 percent.

(ii) The density (d) of the asphalt shall be computed using the following equation:

$$d = K_1 - K_2 T_i$$

Where:

d = Density of the asphalt, kg/m³ (lb/ft³)

K_1 = 1056.1 kg/m³ (metric units)

= 64.70 lb/ft³ (English Units)

K_2 = 0.6176 kg/(m³ °C) (metric units)

= 0.0694 lb/(ft³ °F) (English Units)

T_i = temperature at the start of the blow, °C (deg;F)

(5) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(d) The Administrator will determine compliance with the standards in §60.472(a)(3) by using Method 22, modified so that readings are recorded every 15 seconds for a period of consecutive observations during representative conditions (in accordance with §60.8(c)) totaling 60 minutes. A performance test shall consist of one run.

(e) The owner or operator shall use the monitoring device in §60.473 (a) or (b) to monitor and record continuously the temperature during the particulate matter run and shall report the results to the Administrator with the performance test results.

(f) If at a later date the owner or operator believes that the emission limits in §60.472(a) and (b) are being met even though one of the conditions listed in this paragraph exist, he may submit a written request to the Administrator to repeat the performance test and procedure outlined in paragraph (c) of this section.

(1) The temperature measured in accordance with §60.473(a) is exceeding that measured during the performance test.

(2) The temperature measured in accordance with §60.473(b) is lower than that measured during the performance test.

(g) If fuel oil is to be used to fire an afterburner used to control emissions from a blowing still, the owner or operator may petition the Administrator in accordance with §60.11(e) of the General Provisions to establish an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. To obtain this opacity standard, the owner or operator must request the Administrator to determine opacity during an initial, or subsequent, performance test when fuel oil is used to fire the afterburner. Upon receipt of the results of the performance test, the Administrator will make a finding concerning compliance with the mass standard for the blowing still. If the Administrator finds that the facility was in compliance with the mass standard during the performance test but failed to meet the zero opacity standard, the Administrator will establish and promulgate in the FEDERAL REGISTER an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner.

When the afterburner is fired with natural gas, the zero percent opacity remains the applicable opacity standard.

[54 FR 6677, Feb. 14, 1989, as amended 54 FR 27016, June 27, 1989; 65 FR 61762, Oct. 17, 2000]

Appendix I

Environmental Protection Agency

§ 60.480

K'=conversion factor, 1000 kg/Mg (2000 lb/ton).

θ=duration of test run, hr.

(i) The volume (V) of asphalt charged shall be measured by any means accurate to within 10 percent.

(ii) The density (d) of the asphalt shall be computed using the following equation:

$$d = K_1 - K_2 T_i$$

Where:

d = Density of the asphalt, kg/m³ (lb/ft³)

K₁ = 1056.1 kg/m³ (metric units)

= 64.70 lb/ft³ (English Units)

K₂ = 0.6176 kg/(m³ °C) (metric units)

= 0.0694 lb/(ft³ °F) (English Units)

T_i = temperature at the start of the blow, °C ((°deg;F)

(5) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(d) The Administrator will determine compliance with the standards in § 60.472(a)(3) by using Method 22, modified so that readings are recorded every 15 seconds for a period of consecutive observations during representative conditions (in accordance with § 60.8(c)) totaling 60 minutes. A performance test shall consist of one run.

(e) The owner or operator shall use the monitoring device in § 60.473 (a) or (b) to monitor and record continuously the temperature during the particulate matter run and shall report the results to the Administrator with the performance test results.

(f) If at a later date the owner or operator believes that the emission limits in § 60.472(a) and (b) are being met even though one of the conditions listed in this paragraph exist, he may submit a written request to the Administrator to repeat the performance test and procedure outlined in paragraph (c) of this section.

(1) The temperature measured in accordance with § 60.473(a) is exceeding that measured during the performance test.

(2) The temperature measured in accordance with § 60.473(b) is lower than that measured during the performance test.

(g) If fuel oil is to be used to fire an afterburner used to control emissions from a blowing still, the owner or operator may petition the Administrator in

accordance with § 60.11(e) of the General Provisions to establish an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. To obtain this opacity standard, the owner or operator must request the Administrator to determine opacity during an initial, or subsequent, performance test when fuel oil is used to fire the afterburner. Upon receipt of the results of the performance test, the Administrator will make a finding concerning compliance with the mass standard for the blowing still. If the Administrator finds that the facility was in compliance with the mass standard during the performance test but failed to meet the zero opacity standard, the Administrator will establish and promulgate in the FEDERAL REGISTER an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. When the afterburner is fired with natural gas, the zero percent opacity remains the applicable opacity standard.

[54 FR 6677, Feb. 14, 1989, as amended 54 FR 27016, June 27, 1989; 65 FR 61762, Oct. 17, 2000]

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006

SOURCE: 48 FR 48335, Oct. 18, 1983, unless otherwise noted.

§ 60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 5, 1981, and on or before November 7, 2006, shall

§ 60.481

be subject to the requirements of this subpart.

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

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482–1 through 60.482–10.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482–1 through 60.482–10.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482–1 through 60.482–10.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482–1 through 60.482–10.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482 through 60.487 for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of § 60.485(d), (e), and (f) and § 60.486(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners and operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part

40 CFR Ch. I (7–1–14 Edition)

65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Subpart VVa.* Owners or operators may choose to comply with the provisions of subpart VVa of this part 60 to satisfy the requirements of this subpart VV for an affected facility.

(f) *Stay of standards.* Owners or operators are not required to comply with the definition of “process unit” in § 60.481 and the requirements in § 60.482–1(g) of this subpart until the EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER. While the definition of “process unit” is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 72 FR 64879, Nov. 16, 2007; 73 FR 31379, June 2, 2008; 73 FR 31375, June 2, 2008]

§ 60.481 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of part 60, and the following terms shall have the specific meanings given them.

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:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575$

Environmental Protection Agency

§ 60.481

log X, where X is 1982 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

TABLE FOR DETERMINING APPLICABLE VALUE FOR B

Subpart applicable to facility	Value of B to be used in equation
VV	12.5
DDD	12.5
GGG	7.0
KKK	4.5

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this subpart.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often

has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, PO Box 2300, Fairfield, NJ 07007-2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485(e).

In-situ sampling systems means non-extractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa)(0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485(d) specify how to determine that a piece of equipment is not in VOC service.)

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482–1(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process

unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482–2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482–3(f), and 60.482–10(f)(1)(ii), is re-monitored as specified in § 60.485(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges, or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart,

Environmental Protection Agency

§ 60.482-1

any reactive organic compounds as defined in § 60.2 Definitions.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 49 FR 26738, June 29, 1984; 60 FR 43258, Aug. 18, 1995; 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 72 FR 64879, Nov. 16, 2007]

EFFECTIVE DATE NOTE: At 73 FR 31375, June 2, 2008, in § 60.481, the definition of “process unit” was stayed until further notice.

§ 60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482-1 through 60.482-10 or § 60.480(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in § 60.484.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of § 60.482-2, § 60.482-3, § 60.482-5, § 60.482-6, § 60.482-7, § 60.482-8, or § 60.482-10, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482-2 to 60.482-10 if it is identified as required in § 60.486(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hours (hr)/yr is excluded from the requirements of §§ 60.482-2 through 60.482-10 if it is identified as required in § 60.486(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps and valves at the frequency specified in the following table instead of monitoring as specified in §§ 60.482-2, 60.482-7, and 60.483-2:

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters.	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.*, once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual

amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to subpart VVa of this part, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to subpart VVa of this part, the storage vessel is assigned to any process unit subject to this subpart. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 78276, Dec. 14, 2000; 72 FR 64880, Nov. 16, 2007]

EFFECTIVE DATE NOTE: At 73 FR 31375, June 2, 2008, in § 60.482-1, paragraph (g) was stayed until further notice.

§ 60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485(b), except as provided in § 60.482-1(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482-1(c) and (f) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482-1(f).

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure

specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection if the instrument reading for that monitoring event was less than 10,000 ppm and the pump was not repaired since that monitoring event.

(i) Monitor the pump within 5 days as specified in § 60.485(b). If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak within 15 days of detection by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

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

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is—

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

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10; or

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

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

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

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section.

(A) Monitor the pump within 5 days as specified in § 60.485(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) of this section is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from

the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482-10, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 72 FR 64880, Nov. 16, 2007]

§ 60.482-3 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482-10; or

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

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

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

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas

system or to a control device that complies with the requirements of § 60.482-10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000; 72 FR 64881, Nov. 16, 2007]

§ 60.482-4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482-9.

(2) No later than 5 calendar days after the pressure release, the pressure

relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 60.482-9.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000]

§ 60.482-5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482-1(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected

are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in § 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of § 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of §§ 61.343 through 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

[60 FR 43258, Aug. 18, 1995, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78277, Dec. 14, 2000; 72 FR 64881, Nov. 16, 2007]

§ 60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

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

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

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

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

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22607, May 30, 1984; 65 FR 78277, Dec. 14, 2000; 72 FR 64881, Nov. 16, 2007]

§ 60.482-7 Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1(c) and (f), and §§ 60.483-1 and 60.483-2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the

process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1(c), and §§ 60.483-1 and 60.483-2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the valves on the process unit are monitored in accordance with § 60.483-1 or § 60.483-2, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483-2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into 2 or 3 subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482-9.

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

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;

Environmental Protection Agency

§ 60.482-9

(3) Tightening of packing gland nuts;
(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either becomes an affected facility through § 60.14 or § 60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61762, Oct. 17, 2000; 72 FR 64881, Nov. 16, 2007]

§ 60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482-2(c)(2) and 60.482-7(e).

[48 CFR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

§ 60.482-10

40 CFR Ch. I (7-1-14 Edition)

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10.

(d) Delay of repair for pumps will be allowed if:

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

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

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

(f) When delay of repair is allowed for a leaking pump or valve that remains in service, the pump or valve may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 78277, Dec. 14, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485(b).

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

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

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

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (1)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (j)(2) of this section:

(1) The owner or operator determines 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 (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (1)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (k)(3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(1) The owner or operator shall record the information specified in paragraphs (1)(1) through (1)(5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486(c).

(4) For each inspection conducted in accordance with § 60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

[48 FR 48335, Oct. 18, 1983, as amended at 51 FR 2702, Jan. 21, 1986; 60 FR 43258, Aug. 18, 1995; 61 FR 29878, June 12, 1996; 65 FR 78277, Dec. 14, 2000]

§ 60.483-1 Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485(h).

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.483-2 Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0,

an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482-7(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.484 Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

Environmental Protection Agency

§ 60.485

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Ad-

ministrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(3) Any equivalent 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 Clean Air Act.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61762, Oct. 17, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.485 Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the standards in §§ 60.482-1 through 60.483, and 60.484 as follows:

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

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

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

§ 60.485

40 CFR Ch. I (7–1–14 Edition)

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§ 60.482–2(e), 60.482–3(i), 60.482–4, 60.482–7(f), and 60.482–10(e) as follows:

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

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

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.

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

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

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{\max} = K_1 + K_2 H_T$$

Where:

V_{\max} = Maximum permitted velocity, m/sec (ft/sec)

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

K_2 = 0.7084 m⁴/(MJ-sec) (metric units)

= 0.087 ft⁴/(Btu-sec) (English units)

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)/(MJ)/(ppm-scm-kcal) (metric units)
= 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units)

C_i = Concentration of sample component “i,” ppm

H_i = Net heat of combustion of sample component “i” at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration

is between 150 parts per billion by volume and 100 parts per million by volume) and ASTM D2504-67, 77 or 88 (Reapproved 1993) (incorporated by reference—see § 60.17) shall be used to determine the concentration of sample component “i.”

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference—see § 60.17) shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483-1 or § 60.483-2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves

V_L = Number of valves found leaking

V_T = The sum of the total number of valves monitored

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482-7(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

[54 FR 6678, Feb. 14, 1989, as amended at 54 FR 27016, June 27, 1989; 65 FR 61763, Oct. 17, 2000; 72 FR 64882, Nov. 16, 2007]

§ 60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) “Above 10,000” if the maximum instrument reading measured by the methods specified in § 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482–10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482–10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482–2, 60.482–3, 60.482–4, and 60.482–5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482–2, 60.482–3, 60.482–4, and 60.482–5.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482–1 to 60.482–10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482–2(e), 60.482–3(i) and 60.482–7(f).

(ii) The designation of equipment as subject to the requirements of § 60.482–2(e), § 60.482–3(i), or § 60.482–7(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482–4.

(4)(i) The dates of each compliance test as required in §§ 60.482–2(e), 60.482–3(i), 60.482–4, and 60.482–7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482–1(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(f) The following information pertaining to all valves subject to the requirements of § 60.482–7(g) and (h) and to all pumps subject to the requirements of § 60.482–2(g) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483–2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482–2(d)(5) and 60.482–3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000; 65 FR 78278, Dec. 14, 2000; 72 FR 64883, Nov. 16, 2007]

§ 60.487 Reporting requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

(3) Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).

(4) Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3(i) and those compressors complying with § 60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482-7(b) or § 60.483-2,

(ii) Number of valves for which leaks were not repaired as required in § 60.482-7(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482-2(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482-2(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482-3(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482-3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483-1 or 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless 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 the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with

§ 60.488

the requirements established by the State.

[48 FR 48335, Oct. 18, 1983, as amended at 49 FR 22608, May 30, 1984; 65 FR 61763, Oct. 17, 2000; 72 FR 64883, Nov. 16, 2007]

§ 60.488 Reconstruction.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable new facility” under § 60.15: pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the “fixed capital cost of new components” includes the fixed capital cost of all depreciable components (except components specified in § 60.488 (a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the “Applicability and designation of affected facility” section of the appropriate subpart.) For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[49 FR 22608, May 30, 1984]

§ 60.489 List of chemicals produced by affected facilities.

The following chemicals are produced, as intermediates or final products, by process units covered under this subpart. The applicability date for process units producing one or more of these chemicals is January 5, 1981.

CAS No. ^a	Chemical
105-57-7	Acetal.
75-07-0	Acetaldehyde.
107-89-1	Acetaldol.
60-35-5	Acetamide.
103-84-4	Acetanilide.
64-19-7	Acetic acid.
108-24-7	Acetic anhydride.
67-64-1	Acetone.
75-86-5	Acetone cyanohydrin.
75-05-8	Acetonitrile.
98-86-2	Acetophenone.

40 CFR Ch. I (7-1-14 Edition)

CAS No. ^a	Chemical
75-36-5	Acetyl chloride.
74-86-2	Acetylene.
107-02-8	Acrolein.
79-06-1	Acrylamide.
79-10-7	Acrylic acid.
107-13-1	Acrylonitrile.
124-04-9	Adipic acid.
111-69-3	Adiponitrile.
(^b)	Alkyl naphthalenes.
107-18-6	Allyl alcohol.
107-05-1	Allyl chloride.
1321-11-5	Aminobenzoic acid.
111-41-1	Aminoethylethanamine.
123-30-8	p-Aminophenol.
628-63-7, 123-92-2	Amyl acetates.
71-41-0 ^c	Amyl alcohols.
110-58-7	Amyl amine.
543-59-9	Amyl chloride.
110-66-7 ^c	Amyl mercaptans.
1322-06-1	Amyl phenol.
62-53-3	Aniline.
142-04-1	Aniline hydrochloride.
29191-52-4	Anisidine.
100-66-3	Anisole.
118-92-3	Anthranilic acid.
84-65-1	Anthraquinone.
100-52-7	Benzaldehyde.
55-21-0	Benzamide.
71-43-2	Benzene.
98-48-6	Benzenedisulfonic acid.
98-11-3	Benzenesulfonic acid.
134-81-6	Benzil.
76-93-7	Benzilic acid.
65-85-0	Benzoic acid.
119-53-9	Benzoin.
100-47-0	Benzonitrile.
119-61-9	Benzophenone.
98-07-7	Benzo-trichloride.
98-88-4	Benzoyl chloride.
100-51-6	Benzyl alcohol.
100-46-9	Benzylamine.
120-51-4	Benzyl benzoate.
100-44-7	Benzyl chloride.
98-87-3	Benzyl dichloride.
92-52-4	Biphenyl.
80-05-7	Bisphenol A.
10-86-1	Bromobenzene.
27497-51-4	Bromonaphthalene.
106-99-0	Butadiene.
106-98-9	1-butene.
123-86-4	n-butyl acetate.
141-32-2	n-butyl acrylate.
71-36-3	n-butyl alcohol.
78-92-2	s-butyl alcohol.
75-65-0	t-butyl alcohol.
109-73-9	n-butylamine.
13952-84-6	s-butylamine.
75-64-9	t-butylamine.
98-73-7	p-tert-butyl benzoic acid.
107-88-0	1,3-butylene glycol.
123-72-8	n-butyraldehyde.
107-92-6	Butyric acid.
106-31-0	Butyric anhydride.
109-74-0	Butyronitrile.
105-60-2	Caprolactam.
75-1-50	Carbon disulfide.
558-13-4	Carbon tetrabromide.
56-23-5	Carbon tetrachloride.
9004-35-7	Cellulose acetate.
79-11-8	Chloroacetic acid.
108-42-9	m-chloroaniline.
95-51-2	o-chloroaniline.
106-47-8	p-chloroaniline.

Environmental Protection Agency

\$ 60.489

CAS No. ^a	Chemical	CAS No. ^a	Chemical
35913-09-8	Chlorobenzaldehyde.	26761-40-0	Diisodecyl phthalate.
108-90-7	Chlorobenzene.	27554-26-3	Diisooctyl phthalate.
118-91-2, 535-80-8, 74-11-3 ^c .	Chlorobenzoic acid.	674-82-8	Diketene.
2136-81-4, 2136-89-2, 5216-25-1 ^c .	Chlorobenzotrichloride.	124-40-3	Dimethylamine.
1321-03-5	Chlorobenzoyl chloride.	121-69-7	N,N-dimethylaniline.
25497-29-4	Chlorodifluoromethane.	115-10-6	N,N-dimethyl ether.
75-45-6	Chlorodifluoroethane.	68-12-2	N,N-dimethylformamide.
67-66-3	Chloroform.	57-14-7	Dimethylhydrazine.
25586-43-0	Chloronaphthalene.	77-78-1	Dimethyl sulfate.
88-73-3	o-chloronitrobenzene.	75-18-3	Dimethyl sulfide.
100-00-5	p-chloronitrobenzene.	67-68-5	Dimethyl sulfoxide.
25167-80-0	Chlorophenols.	120-61-6	Dimethyl terephthalate.
126-99-8	Chloroprene.	99-34-3	3,5-dinitrobenzoic acid.
7790-94-5	Chlorosulfonic acid.	51-28-5	Dinitrophenol.
108-41-8	m-chlorotoluene.	25321-14-6	Dinitrotoluene.
95-49-8	o-chlorotoluene.	123-91-1	Dioxane.
106-43-4	p-chlorotoluene.	646-06-0	Dioxilane.
75-72-9	Chlorotrifluoromethane.	122-39-4	Diphenylamine.
108-39-4	m-cresol.	101-84-8	Diphenyl oxide.
95-48-7	o-cresol.	102-08-9	Diphenyl thiourea.
106-44-5	p-cresol.	25265-71-8	Dipropylene glycol.
1319-77-3	Mixed cresols.	25378-22-7	Dodecene.
1319-77-3	Cresylic acid.	28675-17-4	Dodecylaniline.
4170-30-0	Crotonaldehyde.	27193-86-8	Dodecylphenol.
3724-65-0	Crotonic acid.	106-89-8	Epichlorohydrin.
98-82-8	Cumene.	64-17-5	Ethanol.
80-15-9	Cumene hydroperoxide.	141-43-5 ^c	Ethanolamines.
372-09-8	Cyanoacetic acid.	141-78-6	Ethyl acetate.
506-77-4	Cyanogen chloride.	141-97-9	Ethyl acetoacetate.
108-80-5	Cyanuric acid.	140-88-5	Ethyl acrylate.
108-77-0	Cyanuric chloride.	75-04-7	Ethylamine.
110-82-7	Cyclohexane.	100-41-4	Ethylbenzene.
108-93-0	Cyclohexanol.	74-96-4	Ethyl bromide.
108-94-1	Cyclohexanone.	9004-57-3	Ethylcellulose.
110-83-8	Cyclohexene.	75-00-3	Ethyl chloride.
108-91-8	Cyclohexylamine.	105-39-5	Ethyl chloroacetate.
111-78-4	Cyclooctadiene.	105-56-6	Ethylcyanoacetate.
112-30-1	Decanol.	74-85-1	Ethylene.
123-42-2	Diacetone alcohol.	96-49-1	Ethylene carbonate.
27576-04-1	Diaminobenzoic acid.	107-07-3	Ethylene chlorohydrin.
95-76-1, 95-82-9, 554-00-7, 608-27-5, 608-31-1, 626-43-7, 27134-27-6, 57311-92-9 ^c .	Dichloroaniline.	107-15-3	Ethylenediamine.
541-73-1	m-dichlorobenzene.	106-93-4	Ethylene dibromide.
95-50-1	o-dichlorobenzene.	107-21-1	Ethylene glycol.
106-46-7	p-dichlorobenzene.	111-55-7	Ethylene glycol diacetate.
75-71-8	Dichlorodifluoromethane.	110-71-4	Ethylene glycol dimethyl ether.
111-44-4	Dichloroethyl ether.	111-76-2	Ethylene glycol monobutyl ether.
107-06-2	1,2-dichloroethane (EDC).	112-07-2	Ethylene glycol monobutyl ether acetate.
96-23-1	Dichlorohydrin.	110-80-5	Ethylene glycol monoethyl ether.
26952-23-8	Dichloropropene.	111-15-9	Ethylene glycol monethyl ether acetate.
101-83-7	Dicyclohexylamine.	109-86-4	Ethylene glycol monomethyl ether.
109-89-7	Diethylamine.	110-49-6	Ethylene glycol monomethyl ether acetate.
111-46-6	Diethylene glycol.	122-99-6	Ethylene glycol monophenyl ether.
112-36-7	Diethylene glycol diethyl ether.	2807-30-9	Ethylene glycol monopropyl ether.
111-96-6	Diethylene glycol dimethyl ether.	75-21-8	Ethylene oxide.
112-34-5	Diethylene glycol monobutyl ether.	60-29-7	Ethyl ether
124-17-4	Diethylene glycol monobutyl ether acetate.	104-76-7	2-ethylhexanol.
111-90-0	Diethylene glycol monoethyl ether.	122-51-0	Ethyl orthoformate.
112-15-2	Diethylene glycol monoethyl ether acetate.	95-92-1	Ethyl oxalate.
111-77-3	Diethylene glycol monomethyl ether.	41892-71-1	Ethyl sodium oxalacetate.
64-67-5	Diethyl sulfate.	50-00-0	Formaldehyde.
75-37-6	Difluoroethane.	75-12-7	Formamide.
25167-70-8	Diisobutylene.	64-18-6	Formic acid.
		110-17-8	Fumaric acid.
		98-01-1	Furfural.
		56-81-5	Glycerol.
		26545-73-7	Glycerol dichlorohydrin.
		25791-96-2	Glycerol triether.
		56-40-6	Glycine.
		107-22-2	Glyoxal.
		118-74-1	Hexachlorobenzene.
		67-72-1	Hexachloroethane.
		36653-82-4	Hexadecyl alcohol.
		124-09-4	Hexamethylenediamine.

CAS No. ^a	Chemical	CAS No. ^a	Chemical
629–11–8	Hexamethylene glycol.	115–77–5	Pentaerythritol.
100–97–0	Hexamethylenetetramine.	109–66–0	n-pentane.
74–90–8	Hydrogen cyanide.	109–67–1	1-pentene
123–31–9	Hydroquinone.	127–18–4	Perchloroethylene.
99–96–7	p-hydroxybenzoic acid.	594–42–3	Perchloromethyl mercaptan.
26760–64–5	Isoamylene.	94–70–2	o-phenetidine.
78–83–1	Isobutanol.	156–43–4	p-phenetidine.
110–19–0	Isobutyl acetate.	108–95–2	Phenol.
115–11–7	Isobutylene.	98–67–9, 585–	Phenolsulfonic acids.
78–84–2	Isobutyraldehyde.	38–6, 609–46–	
79–31–2	Isobutyric acid.	1, 1333–39–7 ^c .	
25339–17–7	Isodecanol.	91–40–7	Phenyl anthranilic acid.
26952–21–6	Isooctyl alcohol.	(^b)	Phenylenediamine.
78–78–4	Isopentane.	75–44–5	Phosgene.
78–59–1	Isophorone.	85–44–9	Phthalic anhydride.
121–91–5	Isophthalic acid.	85–41–6	Phthalimide.
78–79–5	Isoprene.	108–99–6	b-picoline.
67–63–0	Isopropanol.	110–85–0	Piperazine.
108–21–4	Isopropyl acetate.	9003–29–6,	Polybutenes.
75–31–0	Isopropylamine.	25036–29–7 ^c .	
75–29–6	Isopropyl chloride.	25322–68–3	Polyethylene glycol.
25168–06–3	Isopropylphenol.	25322–69–4	Polypropylene glycol.
463–51–4	Ketene.	123–38–6	Propionaldehyde.
(^b)	Linear alkyl sulfonate.	79–09–4	Propionic acid.
123–01–3	Linear alkylbenzene (linear	71–23–8	n-propyl alcohol.
	dodecylbenzene).	107–10–8	Propylamine.
110–16–7	Maleic acid.	540–54–5	Propyl chloride.
108–31–6	Maleic anhydride.	115–07–1	Propylene.
6915–15–7	Malic acid.	127–00–4	Propylene chlorohydrin.
141–79–7	Mesityl oxide.	78–87–5	Propylene dichloride.
121–47–1	Metanilic acid.	57–55–6	Propylene glycol.
79–41–4	Methacrylic acid.	75–56–9	Propylene oxide.
563–47–3	Methallyl chloride.	110–86–1	Pyridine.
67–56–1	Methanol.	106–51–4	Quinone.
79–20–9	Methyl acetate.	108–46–3	Resorcinol.
105–45–3	Methyl acetoacetate.	27138–57–4	Resorcylic acid.
74–89–5	Methylamine.	69–72–7	Salicylic acid.
100–61–8	n-methylaniline.	127–09–3	Sodium acetate.
74–83–9	Methyl bromide.	532–32–1	Sodium benzoate.
37365–71–2	Methyl butynol.	9004–32–4	Sodium carboxymethyl cellulose.
74–87–3	Methyl chloride.	3926–62–3	Sodium chloroacetate.
108–87–2	Methylcyclohexane.	141–53–7	Sodium formate.
1331–22–2	Methylcyclohexanone.	139–02–6	Sodium phenate.
75–09–2	Methylene chloride.	110–44–1	Sorbic acid.
101–77–9	Methylene dianiline.	100–42–5	Styrene.
101–68–8	Methylene diphenyl diisocyanate.	110–15–6	Succinic acid.
78–93–3	Methyl ethyl ketone.	110–61–2	Succinonitrile.
107–31–3	Methyl formate.	121–57–3	Sulfanilic acid.
108–11–2	Methyl isobutyl carbinol.	126–33–0	Sulfolane.
108–10–1	Methyl isobutyl ketone.	1401–55–4	Tannic acid.
80–62–6	Methyl methacrylate.	100–21–0	Terephthalic acid.
77–75–8	Methylpentynol.	79–34–5 ^c	Tetrachloroethanes.
98–83–9	a-methylstyrene.	117–08–8	Tetrachlorophthalic anhydride.
110–91–8	Morpholine.	78–00–2	Tetraethyl lead.
85–47–2	a-naphthalene sulfonic acid.	119–64–2	Tetrahydronaphthalene.
120–18–3	b-naphthalene sulfonic acid.	85–43–8	Tetrahydrophthalic anhydride.
90–15–3	a-naphthol.	75–74–1	Tetramethyl lead.
135–19–3	b-naphthol.	110–60–1	Tetramethylenediamine.
75–98–9	Neopentanoic acid.	110–18–9	Tetramethylethylenediamine.
88–74–4	o-nitroaniline.	108–88–3	Toluene.
100–01–6	p-nitroaniline.	95–80–7	Toluene-2,4-diamine.
91–23–6	o-nitroanisole.	584–84–9	Toluene-2,4-diisocyanate.
100–17–4	p-nitroanisole.	26471–62–5	Toluene diisocyanates (mixture).
98–95–3	Nitrobenzene.	1333–07–9	Toluenesulfonamide.
27178–83–2 ^c	Nitrobenzoic acid (o,m, and p).	104–15–4 ^c	Toluenesulfonic acids.
79–24–3	Nitroethane.	98–59–9	Toluenesulfonyl chloride.
75–52–5	Nitromethane.	26915–12–8	Toluidines.
88–75–5	2-Nitrophenol.	87–61–6, 108–	Trichlorobenzenes.
25322–01–4	Nitropropane.	70–3, 120–82–	
1321–12–6	Nitrotoluene.	1 ^c .	
27215–95–8	Nonene.	71–55–6	1,1,1-trichloroethane.
25154–52–3	Nonylphenol.	79–00–5	1,1,2-trichloroethane.
27193–28–8	Octylphenol.	79–01–6	Trichloroethylene.
123–63–7	Paraldehyde.	75–69–4	Trichlorofluoromethane.

Environmental Protection Agency

§ 60.480a

CAS No. ^a	Chemical
96-18-4	1,2,3-trichloropropane.
76-13-1	1,1,2-trichloro-1,2,2-trifluoroethane.
121-44-8	Triethylamine.
112-27-6	Triethylene glycol.
112-49-2	Triethylene glycol dimethyl ether.
7756-94-7	Triisobutylene.
75-50-3	Trimethylamine.
57-13-6	Urea.
108-05-4	Vinyl acetate.
75-01-4	Vinyl chloride.
75-35-4	Vinylidene chloride.
25013-15-4	Vinyl toluene.
1330-20-7	Xylenes (mixed).
95-47-6	o-xylene.
106-42-3	p-xylene.
1300-71-6	Xylenol.
1300-73-8	Xylidine.

^aCAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

^bNo CAS number(s) have been assigned to this chemical, its isomers, or mixtures containing these chemicals.

^cCAS numbers for some of the isomers are listed; the standards apply to all of the isomers and mixtures, even if CAS numbers have not been assigned.

[48 FR 48335, Oct. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000]

Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

SOURCE: 72 FR 64883, Nov. 16, 2007, unless otherwise noted.

§ 60.480a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by

itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482-1a through 60.482-11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482-1a through 60.482-11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482-1a through 60.482-11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482-1a through 60.482-11a.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of

Appendix J

Subpart GGG—National Emission Standards for Pharmaceuticals Production

§63.1250 Applicability.

(a) *Definition of affected source.* (1) The affected source subject to this subpart consists of the pharmaceutical manufacturing operations as defined in §63.1251. Except as specified in paragraph (d) of this section, the provisions of this subpart apply to pharmaceutical manufacturing operations that meet the criteria specified in paragraphs (a)(1) (i) through (iii) of this section:

- (i) Manufacture a pharmaceutical product as defined in §63.1251;
- (ii) Are located at a plant site that is a major source as defined in section 112(a) of the Act; and
- (iii) Process, use, or produce HAP.

(2) Determination of the applicability of this subpart shall be reported as part of an operating permit application or as otherwise specified by the permitting authority.

(b) *New source applicability.* A new affected source subject to this subpart and to which the requirements for new sources apply is: An affected source for which construction or reconstruction commenced after April 2, 1997, and the standard was applicable at the time of construction or reconstruction; or a pharmaceutical manufacturing process unit (PMPU) dedicated to manufacturing a single product that has the potential to emit 10 tons per year of any one HAP or 25 tons per year of combined HAP for which construction commenced after April 2, 1997 or reconstruction commenced after October 21, 1999.

(c) *General provisions.* Table 1 of this subpart specifies and clarifies the provisions of subpart A of this part that apply to an owner or operator of an affected source subject to this subpart. The provisions of subpart A specified in Table 1 are the only provisions of subpart A that apply to an affected source subject to this subpart.

(d) *Processes exempted from the affected source.* The provisions of this subpart do not apply to research and development facilities.

(e) *Storage tank ownership determination.* The owner or operator shall follow the procedures specified in paragraphs (e)(1) through (5) of this section to determine to which PMPU a storage tank shall belong. If an owner or operator produces only pharmaceutical products, the procedures specified in paragraphs (e)(1) through (5) of this section are required only to determine applicability and demonstrate compliance with the pollution-prevention alternative specified in §63.1252(e), or to determine new source applicability for a PMPU dedicated to manufacturing a single product as specified in paragraph (b) of this section.

(1) If a storage tank is dedicated to a single PMPU, the storage tank shall belong to that PMPU.

(2) If a storage tank is shared among process units (including at least one PMPU), then the storage tank shall belong to the process unit located on the same plant site as the storage tank that has the greatest annual volume input into or output from the storage tank (i.e., said PMPU or process unit has the predominant use of the storage tank).

(3) If predominant use cannot be determined for a storage tank that is shared among process units (including at least one PMPU), then the owner or operator shall assign the storage tank to any one of the PMPU's that shares it and is also subject to this subpart.

(4) If the predominant use of a storage tank varies from year to year, then predominant use shall be determined based on the utilization that occurred during the year preceding September 21, 1998 for existing affected sources. For new affected sources, predominant use will be based on the first year after initial startup. The determination of predominant use shall be reported in the Notification of Compliance Status required by §63.1260(f). If the predominant use changes, the redetermination of predominant use shall be reported in the next Periodic report.

(5) If the storage tank begins receiving material from (or sending material to) another PMPU, or ceases to receive material from (or send material to) a PMPU, or if the applicability of this subpart to a storage tank has been determined according to the provisions of paragraphs (e)(1) through (4) of this section and there is a significant change in the use of the storage tank that could reasonably change the predominant use, the owner or operator shall reevaluate the applicability of this subpart to the storage tank and report such changes to EPA in the next Periodic report.

(f) *Compliance dates.* The compliance dates for affected sources are as follows:

(1) An owner or operator of an existing affected source must comply with the provisions of this subpart no later than October 21, 2002.

(2) An owner or operator of a new or reconstructed affected source must comply with the provisions of this subpart on August 29, 2000 or upon startup, whichever is later.

(3) Notwithstanding the requirements of paragraph (f)(2) of this section, a new source which commences construction or reconstruction after April 2, 1997 and before September 21, 1998 shall not be required to comply with this subpart until September 21, 2001 if:

(i) The requirements of this subpart are more stringent than the requirements of this subpart in effect before August 29, 2000 and contained in the 40 CFR, part (63.1200-end), edition revised as of July 1, 2000; and

(ii) The owner or operator complies with the requirements published on April 2, 1997 (62 FR 15754) during the period until September 21, 2001.

(4) Notwithstanding the requirements of paragraph (f)(2) of this section, a new source which commences construction or reconstruction after September 21, 1998 and before April 10, 2000 shall not be required to comply with this subpart until October 21, 2002 if:

(i) The requirements of this subpart are more stringent than the requirements of this subpart in effect before August 29, 2000; and

(ii) The owner or operator complies with the requirements of this subpart in effect before August 29, 2000 during the period between startup and October 21, 2002.

(5) Notwithstanding the requirements of paragraph (f)(2) of this section, a new source which commences construction or reconstruction after April 10, 2000 and before August 29, 2000 shall not be required to comply with this subpart until August 29, 2001 if:

(i) The requirements of this subpart are more stringent than the requirements published on April 10, 2000 (65 FR 19152); and

(ii) The owner or operator complies with the requirements of this subpart in effect before August 29, 2000 during the period between startup and August 29, 2001.

(6) Pursuant to section 112(i)(3)(B) of the Act, an owner or operator may request an extension allowing the existing source up to 1 additional year to comply with section 112(d) standards.

(i) For purposes of this subpart, a request for an extension shall be submitted no later than 120 days prior to the compliance dates specified in paragraphs (f) (1) through (5) of this section, except as provided in paragraph (f)(6)(ii) of this section. The dates specified in §63.6(i) for submittal of requests for extensions shall not apply to sources subject to this subpart.

(ii) An owner or operator may submit a compliance extension request after the date specified in paragraph (f)(6)(i) of this section provided the need for the compliance extension arose after that date and before the otherwise applicable compliance date, and the need arose due to circumstances beyond reasonable control of the owner or operator. This request shall include the data described in §63.6(i)(6)(i) (A), (B), (C), and (D).

(g) *Applicability of this subpart.* (1) Each provision set forth in this subpart shall apply at all times, except that the provisions set forth in §63.1255 of this subpart shall not apply during periods of nonoperation of the PMPU (or specific portion thereof) in which the lines are drained and depressurized resulting in the cessation of the emissions to which §63.1255 of this subpart applies.

(2) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the emissions limitations of this subpart during times when emissions (or, where applicable, wastewater streams or residuals) are being routed to such items of equipment, if the shutdown would contravene emissions limitations of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage to a PMPU or portion thereof.

(3) At all times, each owner or operator must operate and maintain any affected source subject to the requirements of this subpart, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control

practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation 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, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(4) In response to an action to enforce the standards set forth in this subpart, an owner or operator may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined in §63.2. Appropriate penalties may be assessed, however, if owner or operator fails to meet the burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(i) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of a facility must timely meet the notification requirements of paragraph (g)(4)(ii) of this section, and must prove by a preponderance of evidence that:

(A) The excess emissions were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, or a process to operate in a normal and usual manner; and could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and did not stem from any activity or event that could have been foreseen and avoided, or planned for; and were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(B) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs;

(C) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(D) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(E) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health;

(F) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices;

(G) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs;

(H) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(I) The owner or operator has prepared a written root cause analysis, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using the best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(ii) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (g)(4)(i) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

(h) *Consistency with other regulations—(1) Compliance with other MACT standards.* (i) After the compliance dates specified in this section, an affected source subject to the provisions of this subpart that is also subject to the provisions of any other subpart of this part 63 may elect to comply with either the provisions of this subpart or the provisions of another applicable subpart governing the maintenance of records and reporting to EPA. The affected source shall identify in the Notification of Compliance Status report required by §63.1260(f) under which authority such records will be maintained.

(ii) After the compliance dates specified in paragraph (f) of this section, at an offsite reloading or cleaning facility subject to §63.1253(f), compliance with the emission standards and associated initial compliance, monitoring, recordkeeping, and reporting provisions of any other subpart of this part 63 constitutes compliance with the provisions of §63.1253(f)(7) (ii) or (iii). The owner or operator of the affected storage tank shall identify in the Notification of Compliance Status report required by §63.1260(f) the subpart of this part 63 with which the owner or operator of the offsite reloading or cleaning facility complies.

(2) *Consistency with 40 CFR parts 264 and 265, subparts AA, BB, and/or CC.* (i) After the compliance dates specified in this section, if any control device subject to this subpart is also subject to monitoring, recordkeeping, and reporting requirements in 40 CFR part 264, subpart AA, BB, or CC, or is subject to monitoring and recordkeeping requirements in 40 CFR part 265, subpart AA, BB, or CC, and the owner or operator complies with the periodic reporting requirements under 40 CFR part 264, subpart AA, BB, or CC that would apply to the device if the facility had final-permitted status, the owner or operator may elect to comply either with the monitoring, recordkeeping, and reporting requirements of this subpart, or with the monitoring, recordkeeping, and reporting requirements in 40 CFR parts 264 and/or 265, as described in this paragraph, which shall constitute compliance with the monitoring, recordkeeping, and reporting requirements of this subpart. If the owner or operator elects to comply with the monitoring,

recordkeeping, and reporting requirements in 40 CFR parts 264 and/or 265, the owner or operator shall report all information required by §63.1260(g) and (i). The owner or operator shall identify in the Notification of Compliance Status, required by §63.1260(f), the monitoring, recordkeeping, and reporting authority under which the owner or operator will comply.

(ii) After the compliance dates specified in this section, if any equipment at an affected source that is subject to §63.1255, is also subject to 40 CFR part 264, subpart BB, or to 40 CFR part 265, subpart BB, then compliance with the recordkeeping and reporting requirements of 40 CFR parts 264 and/or 265 may be used to comply with the recordkeeping and reporting requirements of §63.1255, to the extent that the requirements of 40 CFR parts 264 and/or 265 duplicate the requirements of §63.1255. The owner or operator shall identify in the Notification of Compliance Status, required by §63.1260(f), if the owner or operator will comply with the recordkeeping and reporting authority under 40 CFR parts 264 and/or 265.

(3) *Compliance with 40 CFR 60.112(b).* After the compliance dates specified in this section, a storage tank controlled with a floating roof and in compliance with the provisions of 40 CFR 60.112b, subpart Kb, constitutes compliance with the provisions of this subpart GGG. A storage tank with a fixed roof, closed vent system, and control device in compliance with the provisions of 40 CFR 60.112b, subpart Kb must comply with the monitoring, recordkeeping, and reporting provisions of this subpart GGG. The owner or operator shall identify in the Notification of Compliance Status report required by §63.1260(f) which tanks are in compliance with subpart Kb.

(4) *Compliance with subpart I of this part.* After the compliance dates specified in this section, an affected source with equipment subject to subpart I of this part may elect to comply with either the provisions of §63.1255 or the provisions of subpart H of this part for all such equipment. The owner or operator shall identify in the Notification of Compliance Status report required by §63.1260(f) the provisions with which the owner elects to comply.

(5) *Compliance with other regulations for wastewater.* After the compliance dates specified in this section, the owner or operator of an affected wastewater stream that is also subject to provisions in 40 CFR parts 260 through 272 may elect to determine whether this subpart or 40 CFR parts 260 through 272 contain the more stringent control requirements (e.g., design, operation, and inspection requirements for waste management units; numerical treatment standards; etc.) and the more stringent testing, monitoring, recordkeeping, and reporting. Compliance with provisions of 40 CFR parts 260 through 272 that are determined to be more stringent than the requirements of this subpart constitutes compliance with this subpart. For example, provisions of 40 CFR parts 260 through 272 for treatment units that meet the conditions specified in §63.1256(g)(13) constitute compliance with this subpart. In the Notification of Compliance Status report required by §63.1260(f), the owner or operator shall identify the more stringent provisions of 40 CFR parts 260 through 272 with which the owner or operator will comply. The owner or operator shall also identify in the Notification of Compliance Status report required by §63.1260(f) the information and procedures used to make any stringency determinations. If the owner or operator does not elect to determine the more stringent requirements, the owner or operator must comply with both the provisions of 40 CFR parts 260 through 272 and the provisions of this subpart.

(6) *Compliance with subpart PPP of this part.* After the compliance dates specified in this section, an affected source with equipment in a pharmaceutical manufacturing process unit that is also part of an affected source under subpart PPP of this part may elect to demonstrate compliance with §63.1254 by controlling all process vents in accordance with §63.1425 (b), (c)(1), (c)(3), (d), and/or (f). Alternatively, the owner or operator may elect to determine which process vents must be controlled to comply with the percent reduction requirements of §63.1254 and control only those vents in accordance with §63.1425 (b), (c)(1), (c)(3), (d), and/or (f). For any pharmaceutical manufacturing process unit controlled in accordance with the requirements of §63.1425, the owner or operator must also comply with all other requirements in subpart PPP of this part. In the Notification of Compliance Status report required by §63.1260(f), the owner or operator shall identify which pharmaceutical manufacturing process units are meeting the control requirements for process vents and all other requirements of subpart PPP of this part, and the owner or operator shall describe the calculations and other information used to identify which process vents must be controlled to comply with the percent reduction requirements of §63.1254, if applicable.

(i) For the purposes of establishing whether a person is in violation of this subpart, nothing in this subpart shall preclude the use of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52596, Aug. 29, 2000; 66 FR 40131, Aug. 2, 2001; 76 FR 22599, Apr. 21, 2011]

§63.1251 Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this section. If the same term is defined in subpart A of this part and in this section, it shall have the meaning given in this section for the purposes of this subpart.

Active ingredient means any material that is intended to furnish pharmacological activity or other direct effect in the diagnosis, cure, mitigation, treatment, or prevention of disease, or to affect the structure or any function of the body of man or other animals. This term does not include food, food additives (except vitamins and other materials described by SIC code 2833 or 2834), color additives, cosmetics, in-vitro diagnostic substances, x-ray film, test indicator devices, and medical devices such as implants, artificial joints, surgical bandages, and stitching material.

Actual HAP emissions means the HAP emitted to the atmosphere from either uncontrolled or controlled emission points.

Affirmative defense means, in the context of an enforcement proceeding, a response or a defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Air pollution control device or Control device means equipment installed on a process vent, storage tank, wastewater treatment exhaust stack, or combination thereof that reduces the mass

of HAP emitted to the air. The equipment may consist of an individual device or a series of devices. Examples include, but are not limited to, incinerators, carbon adsorption units, condensers, flares, boilers, process heaters, and gas absorbers. Process condensers are not considered air pollution control devices or control devices.

Annual average concentration, as used in the wastewater provisions in §63.1256, means the total mass of partially soluble and/or soluble HAP compounds in a wastewater stream during the calendar year divided by the total mass of the wastewater stream discharged during the same calendar year, as determined according to the procedures specified in §63.1257(e)(1) (i) and (ii).

Automated monitoring and recording system means any means of measuring values of monitored parameters and creating a hard copy or computer record of the measured values that does not require manual reading of monitoring instruments and manual transcription of data values. Automated monitoring and recording systems include, but are not limited to, computerized systems and strip charts.

Batch emission episode means a discrete venting episode that may be associated with a single unit operation. A unit operation may have more than one batch emission episode. For example, a displacement of vapor resulting from the charging of a vessel with HAP will result in a discrete emission episode that will last through the duration of the charge and will have an average flowrate equal to the rate of the charge. If the vessel is then heated, there will also be another discrete emission episode resulting from the expulsion of expanded vapor. Both emission episodes may occur in the same vessel or unit operation. There are possibly other emission episodes that may occur from the vessel or other process equipment, depending on process operations.

Batch operation or Batch process means a noncontinuous operation involving intermittent or discontinuous feed into equipment, and, in general, involves the emptying of the equipment after the batch operation ceases and prior to beginning a new operation. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation.

Bench-scale batch process means a batch process (other than a research and development facility) that is capable of being located on a laboratory bench top. This bench-scale equipment will typically include reagent feed vessels, a small reactor and associated product separator, recovery and holding equipment. These processes are only capable of producing small quantities of product.

Block means a time period that comprises a single batch.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator. Boiler also means any industrial furnace as defined in 40 CFR 260.10.

Centralized combustion control device (CCCD) means enclosed combustion devices that are used to control process vent emissions from non-dedicated PMPU's at a facility. Centralized combustion control devices may also be used to control emissions from source types including, but not limited to, storage tanks, waste management units, and equipment leaks.

Cleaning operation means routine rinsing, washing, or boil-off of equipment in batch operations between batches.

Closed biological treatment process means a tank or surface impoundment where biological treatment occurs and air emissions from the treatment process are routed to either a control device by means of a closed-vent system or by means of hard-piping. The tank or surface impoundment has a fixed roof, as defined in this section, or a floating flexible membrane cover that meets the requirements specified in §63.1256(c).

Closed-loop system means an enclosed system that returns process fluid to the process and is not vented to the atmosphere except through a closed-vent system.

Closed-purge system means a system or combination of system and portable containers, to capture purged liquids. Containers must be covered or closed when not being filled or emptied.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device.

Combustion device means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of HAP vapors.

Combustion device burner means a device designed to mix and ignite fuel and air to provide a flame to heat and oxidize waste organic vapors in a combustion device.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are not inaccessible, ceramic, or ceramic-lined as described in §63.1255(b)(1)(vii) and §63.1255(f)(3).

Construction means the onsite fabrication, erection, or installation of an affected source or a PMPU. Addition of new equipment to a PMPU subject to existing source standards does not constitute construction, but it may constitute reconstruction of the affected source or PMPU if it satisfies the definition of reconstruction in this section.

Consumption means the quantity of all HAP raw materials entering a process in excess of the theoretical amount used as reactant, assuming 100 percent stoichiometric conversion. The raw materials include reactants, solvents, and any other additives. If a HAP is generated in the process as well as added as a raw material, consumption includes the quantity generated in the process.

Container, as used in the wastewater provisions, means any portable waste management unit that has a capacity greater than or equal to 0.1 m³ in which a material is stored, transported, treated,

or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Continuous process means a process where the inputs and outputs flow continuously throughout the duration of the process. Continuous processes are typically steady state.

Continuous recorder means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values.

Continuous seal means a seal that forms a continuous closure that completely covers the space between the wall of the storage tank and the edge of the floating roof. A continuous seal may be a vapor-mounted, liquid-mounted, or metallic shoe seal.

Control device, for purposes of this §63.1255, means any equipment used for recovering or oxidizing organic hazardous air pollutant vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, flares, boilers, and process heaters.

Controlled HAP emissions means the quantity of HAP discharged to the atmosphere from an air pollution control device.

Cover, as used in the wastewater provisions, means a device or system which is placed on or over a waste management unit containing wastewater or residuals so that the entire surface area is enclosed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed when not in use. Examples of covers include a fixed roof installed on a wastewater tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

Dedicated PMPU means a PMPU that is composed of equipment that is used to manufacture the same product for a continuous period of 6 months or greater. The PMPU includes any shared storage tank(s) that are determined to belong to the PMPU according to the procedures in §63.1250(e).

Dense gas system means a conveyance system operated to limit oxygen levels below 12 percent.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Enhanced biological treatment system or enhanced biological treatment process means an aerated, thoroughly mixed treatment unit(s) that contains biomass suspended in water followed by a clarifier that removes biomass from the treated water and recycles recovered biomass to the aeration unit. The mixed liquor volatile suspended solids (biomass) is greater than 1 kilogram per

cubic meter throughout each aeration unit. The biomass is suspended and aerated in the water of the aeration unit(s) by either submerged air flow or mechanical agitation. A thoroughly mixed treatment unit is a unit that is designed and operated to approach or achieve uniform biomass distribution and organic compound concentration throughout the aeration unit by quickly dispersing the recycled biomass and the wastewater entering the unit.

Equipment, for purposes of §63.1255, means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, and instrumentation system in organic hazardous air pollutant service; and any control devices or closed-vent systems required by this subpart.

Excipient means any substance other than the active drug or product which has been appropriately evaluated for safety and is included in a drug delivery system to either aid the processing of the drug delivery system during its manufacture; protect, support, or enhance stability, bioavailability, or patient acceptability; assist in product identification; or enhance any other attribute of the overall safety and effectiveness of the drug delivery system during storage or use.

External floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a storage tank or waste management unit with no fixed roof.

Fill or filling means the introduction of material into a storage tank or the introduction of a wastewater stream or residual into a waste management unit, but not necessarily to complete capacity.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere.

Fixed roof means a cover that is mounted on a waste management unit or storage tank in a stationary manner and that does not move with fluctuations in liquid level.

Floating roof means a cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and waste management unit or storage tank wall.

Flow indicator means a device which indicates whether gas flow is, or whether the valve position would allow gas flow to be, present in a line.

Formulation means the process of mixing, blending, or diluting one or more active or inert ingredients with one or more active or inert ingredients, without an intended chemical reaction, to obtain a pharmaceutical dosage form. Formulation operations include mixing, compounding, blending, and tablet coating.

Group of processes means all of the equipment associated with processes in a building, processing area, or facility-wide. For a dedicated process, a group of processes may consist of a single process.

Halogen atoms mean atoms of chlorine or fluorine.

Halogenated compounds means organic HAP compounds that contain halogen atoms.

Halogenated vent stream or Halogenated stream means a process, storage tank, or waste management unit vent determined to have a concentration of halogenated compounds of greater than 20 ppmv, as determined through process knowledge, test results using Method 18 of 40 CFR part 60, appendix A, or test results using any other test method that has been validated according to the procedures in Method 301 of appendix A of this part.

Hard-piping means piping or tubing that is manufactured and properly installed using good engineering judgment and standards, such as ANSI B31-3.

Hydrogen halides and halogens means hydrogen chloride (HCl), chlorine (Cl₂), and hydrogen fluoride (HF).

In gas/vapor service means that a piece of equipment in organic hazardous air pollutant service contains a gas or vapor at operating conditions.

In heavy liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service or in light liquid service.

In light liquid service means that a piece of equipment in organic hazardous air pollutant service contains a liquid that meets the following conditions:

- (1) The vapor pressure of one or more of the organic compounds is greater than 0.3 kilopascals at 20 °C;
- (2) The total concentration of the pure organic compounds constituents having a vapor pressure greater than 0.3 kilopascals at 20 °C is equal to or greater than 20 percent by weight of the total process stream; and
- (3) The fluid is a liquid at operating conditions. (Note: Vapor pressures may be determined by the methods described in 40 CFR 60.485(e)(1).)

In liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service.

In organic hazardous air pollutant or in organic HAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d). The provisions of

§63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals below ambient pressure.

In-situ sampling systems means nonextractive samplers or in-line samplers.

Individual drain system means the stationary system used to convey wastewater streams or residuals to a waste management unit. The term includes hard piping; all process drains and junction boxes; and associated sewer lines, other junction boxes, manholes, sumps, and lift stations conveying wastewater streams or residuals. A segregated stormwater sewer system, which is a drain and collection system designed and operated for the sole purpose of collecting rainfall-runoff at a facility, and which is segregated from all other individual drain systems, is excluded from this definition.

Initial startup means the first time a new or reconstructed source begins production. Initial startup does not include operation solely for testing equipment. Initial startup does not include subsequent start ups (as defined in this section) of processes following malfunctions or process shutdowns.

Internal floating roof means a cover that rests or floats on the liquid surface (but not necessarily in complete contact with it) inside a storage tank or waste management unit that has a permanently affixed roof.

Instrumentation system means a group of equipment components used to condition and convey a sample of the process fluid to analyzers and instruments for the purpose of determining process operating conditions (e.g., composition, pressure, flow, etc.). Valves and connectors are the predominant type of equipment used in instrumentation systems; however, other types of equipment may also be included in these systems. Only valves nominally 0.5 inches and smaller, and connectors nominally 0.75 inches and smaller in diameter are considered instrumentation systems for the purposes of this subpart. Valves greater than nominally 0.5 inches and connectors greater than nominally 0.75 inches associated with instrumentation systems are not considered part of instrumentation systems and must be monitored individually.

Isolated intermediate means a product of a process. An isolated intermediate is usually a product of a chemical synthesis, fermentation, or biological extraction process; several different isolated intermediates may be produced in the manufacture of a finished dosage form of a drug. Precursors, active ingredients, or finished dosage forms are considered isolated intermediates. An isolated intermediate is stored before subsequent processing. Storage occurs at any time the intermediate is placed in equipment used solely for storage, such as drums, totes, day tanks, and storage tanks. The storage of an isolated intermediate marks the end of a process.

Junction box means a manhole or access point to a wastewater sewer system line or a lift station.

Large control device means a control device that controls total HAP emissions of greater than or equal to 10 tons/yr, before control.

Liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage tank or waste management unit and the floating roof. The seal is mounted continuously around the tank or unit.

Liquids dripping means any visible leakage from the seal including dripping, spraying, misting, clouding, and ice formation. Indications of liquid dripping include puddling or new stains that are indicative of an existing evaporated drip.

Maintenance wastewater means wastewater generated by the draining of process fluid from components in the pharmaceutical manufacturing process unit into an individual drain system in preparation for or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewater include descaling of heat exchanger tubing bundles, cleaning of distillation column traps, draining of pumps into an individual drain system, and draining of portions of the pharmaceutical manufacturing process unit for repair. Wastewater from cleaning operations is not considered maintenance wastewater.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, emissions monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused all or in part by poor maintenance or careless operation are not malfunctions.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the total organic HAP in the stored or transferred liquid at the temperature equal to the highest calendar-month average of the liquid storage or transferred temperature for liquids stored or transferred above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored or transferred at the ambient temperature, as determined:

- (1) In accordance with methods described in Chapter 19.2 of the American Petroleum Institute's Manual of Petroleum Measurement Standards, Evaporative Loss From Floating-Roof Tanks (incorporated by reference as specified in §63.14); or
- (2) As obtained from standard reference texts; or
- (3) As determined by the American Society for Testing and Materials Method D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope (incorporated by reference as specified in §63.14); or
- (4) Any other method approved by the Administrator.

Metallic shoe seal or mechanical shoe seal means metal sheets that are held vertically against the wall of the storage tank by springs, weighted levers, or other mechanisms and connected to the floating roof by braces or other means. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

Nondedicated formulation operations means equipment used to formulate numerous products.

Nondedicated recovery device(s) means a recovery device that receives material from more than one PMPU.

Nonrepairable means that it is technically infeasible to repair a piece of equipment from which a leak has been detected without a process shutdown.

Open biological treatment process means a biological treatment process that is not a closed biological treatment process as defined in this section.

Open-ended valve or line means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating scenario for the purposes of reporting and recordkeeping, means any specific operation of a PMPU and includes for each process:

- (1) A description of the process and the type of process equipment used;
- (2) An identification of related process vents and their associated emissions episodes and durations, wastewater PODs, and storage tanks;
- (3) The applicable control requirements of this subpart, including the level of required control, and for vents, the level of control for each vent;
- (4) The control or treatment devices used, as applicable, including a description of operating and/or testing conditions for any associated control device;
- (5) The process vents, wastewater PODs, and storage tanks (including those from other processes) that are simultaneously routed to the control or treatment device(s);
- (6) The applicable monitoring requirements of this subpart and any parametric level that assures compliance for all emissions routed to the control or treatment device;
- (7) Calculations and engineering analyses required to demonstrate compliance; and
- (8) For reporting purposes, a change to any of these elements not previously reported, except for paragraph (5) of this definition, shall constitute a new operating scenario.

Partially soluble HAP means a HAP listed in Table 2 of this subpart.

Pharmaceutical manufacturing operations means the facilitywide collection of PMPU and any other equipment such as heat exchanger systems, wastewater and waste management units, or cooling towers that are not associated with an individual PMPU, but that are located at a facility for the purpose of manufacturing pharmaceutical products and are under common control.

Pharmaceutical manufacturing process unit (PMPU) means the process, as defined in this subpart, and any associated storage tanks, equipment identified in §63.1252(f), and components such as pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems that are used in the manufacturing of a pharmaceutical product.

Pharmaceutical product means any of the following materials, excluding any material that is a nonreactive solvent, excipient, binder, or filler, or any material that is produced in a chemical manufacturing process unit that is subject to the requirements of subparts F and G of this part 63:

- (1) Any material described by the standard industrial classification (SIC) code 2833 or 2834; or
- (2) Any material whose manufacturing process is described by North American Industrial Classification System (NAICS) code 325411 or 325412; or
- (3) A finished dosage form of a drug, for example, a tablet, capsule, solution, etc.; or
- (4) Any active ingredient or precursor that is produced at a facility whose primary manufacturing operations are described by SIC code 2833 or 2834; or
- (5) At a facility whose primary operations are not described by SIC code 2833 or 2834, any material whose primary use is as an active ingredient or precursor.

Plant site means all contiguous or adjoining property that is under common control, including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Point of determination (POD) means the point where a wastewater stream exits the process, storage tank, or last recovery device. If soluble and/or partially soluble HAP compounds are not recovered from water before discharge, the discharge point from the process equipment or storage tank is a POD. If water streams are routed to a recovery device, the discharge from the recovery device is a POD. There can be more than 1 POD per process or PMPU.

Precursor means a material that is manufactured to undergo further chemical change or processing to ultimately manufacture an active ingredient or finished dosage form of a drug. This term does not include commodity chemicals produced by the synthetic organic chemical manufacturing industry.

Pressure release means the emission of materials resulting from the system pressure being greater than the set pressure of the pressure relief device. This release can be one release or a series of releases over a short time period due to a malfunction in the process.

Pressure relief device or valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Primary use means 50 percent or more of a material is used for a particular purpose.

Process means all equipment which collectively function to produce a pharmaceutical product or isolated intermediate (which is also a pharmaceutical product). A process may consist of one or more unit operations. For the purposes of this subpart, process includes any, all, or a combination of reaction, recovery, separation, purification, or other activity, operation, manufacture, or treatment which are used to produce a pharmaceutical product or isolated intermediate. Cleaning operations conducted are considered part of the process. Nondedicated solvent recovery operations located within a contiguous area within the affected source are considered single processes. A storage tank that is used to accumulate used solvent from multiple batches of a single process for purposes of solvent recovery does not represent the end of the process. Nondedicated formulation operations occurring within a contiguous area are considered a single process that is used to formulate numerous materials and/or products. Quality assurance and quality control laboratories are not considered part of any process. Ancillary activities are not considered a process or part of any process. Ancillary activities include boilers and incinerators (not used to comply with the provisions of §63.1253, §63.1254, or §63.1256(h)), chillers and refrigeration systems, and other equipment and activities that are not directly involved (i.e., they operate within a closed system and materials are not combined with process fluids) in the processing of raw materials or the manufacturing of a pharmaceutical product.

Process condenser means a condenser whose primary purpose is to recover material as an integral part of a process. The condenser must support a vapor-to-liquid phase change for periods of source equipment operation that are at or above the boiling or bubble point of substance(s) at the liquid surface. Examples of process condensers include distillation condensers, reflux condensers, and condensers used in stripping or flashing operations. In a series of condensers, all condensers up to and including the first condenser with an exit gas temperature below the boiling or bubble point of the substance(s) at the liquid surface are considered to be process condensers. All condensers in line prior to a vacuum source are included in this definition.

Process shutdown means a work practice or operational procedure that stops production from a process or part of a process during which it is technically feasible to clear process material from a process or part of a process consistent with safety constraints and during which repairs can be effected. An unscheduled work practice or operational procedure that stops production from a process or part of a process for less than 24 hours is not a process shutdown. An unscheduled work practice or operational procedure that would stop production from a process or part of a process for a shorter period of time than would be required to clear the process or part of the process of materials and start up the process, and would result in greater emissions than delay of

repair of leaking components until the next scheduled process shutdown, is not a process shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process shutdowns.

Process tank means a tank that is used to collect material discharged from a feedstock storage tank or unit operation and to transfer this material to another unit operation within the process or to a product storage tank. Surge control vessels and bottoms receivers that fit these conditions are considered process tanks. Product storage tanks are considered process tanks and are part of the PMPU that produce the stored material. For the purposes of this subpart, vents from process tanks are considered process vents.

Process vent means a vent from a unit operation or vents from multiple unit operations within a process that are manifolded together into a common header, through which a HAP-containing gas stream is, or has the potential to be, released to the atmosphere. Examples of process vents include, but are not limited to, vents on condensers used for product recovery, bottom receivers, surge control vessels, reactors, filters, centrifuges, and process tanks. Emission streams that are undiluted and uncontrolled containing less than 50 ppmv HAP, as determined through process knowledge that no HAP are present in the emission stream or using an engineering assessment as discussed in §63.1257(d)(2)(ii); test data using Method 18 of 40 CFR part 60, appendix A-6; Method 320 of 40 CFR part 63; or any other test method that has been validated according to the procedures in Method 301 of appendix A of this part, are not considered process vents. Process vents do not include vents on storage tanks regulated under §63.1253, vents on wastewater emission sources regulated under §63.1256, or pieces of equipment regulated under §63.1255.

Production-indexed HAP consumption factor is the result of dividing the annual consumption of total HAP by the annual production rate, per process.

Production-indexed volatile organic compound (VOC) consumption factor is the result of dividing the annual consumption of total VOC by the annual production rate, per process.

Publicly owned treatment works (POTW) means any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage or industrial wastes of a liquid nature as defined in section 212(2)(A) of the Clean Water Act, as amended [33 U.S.C. §1292(2)(A)]. A POTW includes the treatment works, intercepting sewers, outfall sewers, sewage collection systems, pumping, power, and other equipment. The POTW is defined at 40 CFR 403.3(o).

Reactor means a device or vessel in which one or more chemicals or reactants, other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.

Reconstruction, as used in §63.1250(b), shall have the meaning given in §63.2, except that “affected or previously unaffected stationary source” shall mean either “affected facility” or “PMPU.” As used in §63.1254(a)(3)(ii)(A)(3), reconstruction shall have the meaning given in §63.2, except that “source” shall mean “control device.”

Recovery device, as used in the wastewater provisions, means an individual unit of equipment used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse, or for sale for fuel value, use or reuse. Examples of equipment that may be recovery devices include organic removal devices such as decanters, strippers, or thin-film evaporation units. To be a recovery device, a decanter and any other equipment based on the operating principle of gravity separation must receive only two-phase liquid streams.

Repaired means that equipment:

- (1) Is adjusted, or otherwise altered, to eliminate a leak as defined in the applicable paragraphs of §63.1255, and;
- (2) Is, unless otherwise specified in applicable provisions of §63.1255, monitored as specified in §63.180(b) and (c) as appropriate, to verify that emissions from the equipment are below the applicable leak definition.

Research and development facility means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale in commerce, except in a de minimis manner.

Residual means any HAP-containing liquid or solid material that is removed from a wastewater stream by a waste management unit or treatment process that does not destroy organics (nondestructive unit). Examples of residuals from nondestructive waste management units are: the organic layer and bottom residue removed by a decanter or organic-water separator and the overheads from a steam stripper or air stripper. Examples of materials which are not residuals are: silt; mud; leaves; bottoms from a steam stripper or air stripper; and sludges, ash, or other materials removed from wastewater being treated by destructive devices such as biological treatment units and incinerators.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purposes of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

Set pressure means the pressure at which a properly operating pressure relief device begins to open to relieve atypical process system operating pressure.

Sewer line means a lateral, trunk line, branch line, or other conduit including, but not limited to, grates, trenches, etc., used to convey wastewater streams or residuals to a downstream waste management unit.

Shutdown means the cessation of operation of a continuous process for any purpose. Shutdown also means the cessation of a batch process or any related individual piece of equipment required or used to comply with this subpart as a result of a malfunction or for replacement of equipment, repair, or any other purpose not excluded from this definition. Shutdown also applies to emptying and degassing storage vessels. Shutdown does not apply to cessation of a batch process at the end of a campaign, for routine maintenance, for rinsing or washing of equipment between batches, or other routine operations.

Single-seal system means a floating roof having one continuous seal that completely covers the space between the wall of the storage tank and the edge of the floating roof. This seal may be a vapor-mounted, liquid-mounted, or metallic shoe seal.

Small control device means a control device that controls total HAP emissions of less than 10 tons/yr, before control.

Soluble HAP means a HAP listed in Table 3 of this subpart.

Standard batch means a batch process operated within a range of operating conditions that are documented in an operating scenario. Emissions from a standard batch are based on the operating conditions that result in highest emissions. The standard batch defines the uncontrolled and controlled emissions for each emission episode defined under the operating scenario.

Startup means the setting in operation of a continuous process unit for any purpose; the first time a new or reconstructed batch process unit begins production; for new equipment added, including equipment used to comply with this subpart, the first time the equipment is put into operation; or, for the introduction of a new product/process, the first time the product or process is run in equipment. For batch process units, startup does not apply to the first time the equipment is put into operation at the start of a campaign to produce a product that has been produced in the past, after a shutdown for maintenance, or when the equipment is put into operation as part of a batch within a campaign. As used in §63.1255, startup means the setting in operation of a piece of equipment or a control device that is subject to this subpart.

Storage tank means a tank or other vessel that is used to store organic liquids that contain one or more HAP as raw material feedstocks. Storage tank also means a tank or other vessel in a tank farm that receives and accumulates used solvent from multiple batches of a process or processes for purposes of solvent recovery. The following are not considered storage tanks for the purposes of this subpart:

- (1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;
- (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (3) Vessels storing organic liquids that contain HAP only as impurities;
- (4) Wastewater storage tanks; and
- (5) Process tanks (including product tanks and isolated intermediate tanks).

Supplemental gases are any gaseous streams that are not defined as process vents, or closed-vent systems from wastewater management and treatment units, storage tanks, or equipment components and that contain less than 50 ppmv TOC, as determined through process knowledge, that are introduced into vent streams or manifolds. Air required to operate combustion device burner(s) is not considered supplemental gas.

Surface impoundment means a waste management unit which is a natural topographic depression, manmade excavation, or diked area formed primarily of earthen materials (although it may be lined with manmade materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids. A surface impoundment is used for the purpose of treating, storing, or disposing of wastewater or residuals, and is not an injection well. Examples of surface impoundments are equalization, settling, and aeration pits, ponds, and lagoons.

System flowrate means the flowrate of gas entering the control device.

Total organic compounds (TOC) means those compounds measured according to the procedures of Method 18 or Method 25A, 40 CFR part 60, appendix A.

Treatment process means a specific technique that removes or destroys the organics in a wastewater or residual stream such as a steam stripping unit, thin-film evaporation unit, waste incinerator, biological treatment unit, or any other process applied to wastewater streams or residuals to comply with §63.1256. Most treatment processes are conducted in tanks. Treatment processes are a subset of waste management units.

Uncontrolled HAP emissions means a gas stream containing HAP which has exited the process (or process condenser, if any), but which has not yet been introduced into an air pollution control device to reduce the mass of HAP in the stream. If the process vent is not routed to an air pollution control device, uncontrolled emissions are those HAP emissions released to the atmosphere.

Unit operation means those processing steps that occur within distinct equipment that are used, among other things, to prepare reactants, facilitate reactions, separate and purify products, and recycle materials. Equipment used for these purposes includes but is not limited to reactors, distillation columns, extraction columns, absorbers, decanters, dryers, condensers, and filtration equipment.

Vapor-mounted seal means a continuous seal that completely covers the annular space between the wall of the storage tank or waste management unit and the edge of the floating roof and is mounted such that there is a vapor space between the stored liquid and the bottom of the seal.

Volatile organic compounds (VOC) means those materials defined in 40 CFR 51.100.

Waste management unit means the equipment, structure(s), and or devices used to convey, store, treat, or dispose of wastewater streams or residuals. Examples of waste management units include wastewater tanks, air flotation units, surface impoundments, containers, oil-water or organic-water separators, individual drain systems, biological wastewater treatment units, waste incinerators, and organic removal devices such as steam and air stripper units, and thin film evaporation units. If such equipment is used for recovery then it is part of a pharmaceutical process and is not a waste management unit.

Wastewater means any portion of an individual wastewater stream or any aggregation of wastewater streams.

Wastewater stream means water that is discarded from a PMPU through a single POD, that contains an annual average concentration of partially soluble and/or soluble HAP compounds of at least 5 parts per million by weight and a load of at least 0.05 kg/yr. The following are not considered wastewater streams for the purposes of this subpart:

- (1) Stormwater from segregated sewers;
- (2) Water from fire-fighting and deluge systems, including testing of such systems;
- (3) Spills;
- (4) Water from safety showers;
- (5) Samples of a size not greater than reasonably necessary for the method of analysis that is used;
- (6) Equipment leaks;
- (7) Wastewater drips from procedures such as disconnecting hoses after clearing lines; and
- (8) Noncontact cooling water.

Wastewater tank means a stationary waste management unit that is designed to contain an accumulation of wastewater or residuals and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support. Wastewater tanks used for flow equalization are included in this definition.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52598, Aug. 29, 2000; 71 FR 20459, Apr. 20, 2006; 76 FR 22600, Apr. 21, 2011; 79 FR 11284, Feb. 27, 2014]

§63.1252 Standards: General.

Each owner or operator of any affected source subject to the provisions of this subpart shall control HAP emissions to the level specified in this section on and after the compliance dates specified in §63.1250(f). Initial compliance with the emission limits is demonstrated in accordance with the provisions of §63.1257, and continuous compliance is demonstrated in accordance with the provisions of §63.1258.

(a) *Opening of a safety device.* Opening of a safety device, as defined in §63.1251, is allowed at any time conditions require it to do so to avoid unsafe conditions.

(b) *Closed-vent systems.* The owner or operator of a closed-vent system that contains bypass lines that could divert a vent stream away from a control device used to comply with the requirements in §§63.1253, 63.1254, and 63.1256 shall comply with the requirements of Table 4 to this subpart and paragraph (b)(1) or (2) of this section. Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, rupture disks and pressure relief valves needed for safety purposes are not subject to this paragraph.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether vent stream flow is present at least once every 15 minutes. Records shall be maintained as specified in §63.1259(i)(6)(i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the closed position with a car seal or lock and key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line. Records shall be maintained as specified in §63.1259(i)(6)(ii).

(c) *Heat exchange systems.* Except as provided in paragraph (c)(2) of this section, owners and operators of affected sources shall comply with the requirements in paragraph (c)(1) of this section for heat exchange systems that cool process equipment or materials used in pharmaceutical manufacturing operations.

(1) The heat exchange system shall be treated according to the provisions of §63.104, except that the monitoring frequency shall be no less than quarterly.

(2) For identifying leaking equipment, the owner or operator of heat exchange systems on equipment which meet current good manufacturing practice (CGMP) requirements of 21 CFR part 211 may elect to use the physical integrity of the reactor as the surrogate indicator of heat exchange system leaks around the reactor.

(d) *Emissions averaging provisions.* Except as specified in paragraphs (d)(1) through (5) of this section, owners or operators of storage tanks or processes subject to the provisions of §§63.1253 and 63.1254 may choose to comply by using emissions averaging requirements specified in §63.1257(g) or (h) for any storage tank or process.

(1) A State may prohibit averaging of HAP emissions and require the owner or operator of an existing source to comply with the provisions in §§63.1253 and 63.1254.

(2) Only emission sources subject to the requirements of §63.1253(b)(1) or (c)(1)(i) or §63.1254(a)(1)(i) may be included in any averaging group.

(3) Processes which have been permanently shutdown or storage tanks permanently taken out of HAP service may not be included in any averaging group.

(4) Processes and storage tanks already controlled on or before November 15, 1990 may not be included in an emissions averaging group, except where the level of control is increased after November 15, 1990. In these cases, the uncontrolled emissions shall be the controlled emissions as calculated on November 15, 1990 for the purpose of determining the uncontrolled emissions as specified in §63.1257(g) and (h).

(5) Emission points controlled to comply with a State or Federal rule other than this subpart may not be credited in an emission averaging group, unless the level of control has been increased after November 15, 1990 above what is required by the other State or Federal rule. Only the control above what is required by the other State or Federal rule will be credited. However, if an emission point has been used to generate emissions averaging credit in an approved emissions average, and the point is subsequently made subject to a State or Federal rule other than this subpart, the point can continue to generate emissions averaging credit for the purpose of complying with the previously approved average.

(6) Not more than 20 processes subject to §63.1254(a)(1)(i), and 20 storage tanks subject to §63.1253(b)(1) or (c)(1)(i) at an affected source may be included in an emissions averaging group.

(7) Compliance with the emission standards in §63.1253 shall be satisfied when the annual percent reduction efficiency is greater than or equal to 90 percent for those tanks meeting the criteria of §63.1253(a)(1) and 95 percent for those tanks meeting the criteria of §63.1253(a)(2), as demonstrated using the test methods and compliance procedures specified in §63.1257(g).

(8) Compliance with the emission standards in §63.1254(a)(1)(i) shall be satisfied when the annual percent reduction efficiency is greater than or equal to 93 percent, as demonstrated using the test methods and compliance procedures specified in §63.1257(h).

(e) *Pollution prevention alternative.* Except as provided in paragraph (e)(1) of this section, an owner or operator may choose to meet the pollution prevention alternative requirement specified in either paragraph (e)(2) or (3) of this section for any PMPU or for any situation described in paragraph (e)(4) of this section, in lieu of the requirements specified in §§63.1253, 63.1254, 63.1255, and 63.1256. Compliance with paragraphs (e)(2) and (3) of this section shall be demonstrated through the procedures in §63.1257(f). Any PMPU for which the owner or operator seeks to comply by using the pollution prevention alternative shall begin with the same starting material(s) and end with the same product(s). The owner or operator may not comply with the pollution prevention alternative by eliminating any steps of a process by transferring the step offsite (to another manufacturing location).

(1) The HAP that are generated in the PMPU that are not part of the production-indexed consumption factor must be controlled according to the requirements of §§63.1253, 63.1254, 63.1255, and 63.1256. The hydrogen halides that are generated as a result of combustion control of emissions must be controlled according to the requirements of paragraph (g)(1) of this section.

(2) The production-indexed HAP consumption factor (kg HAP consumed/kg produced) shall be reduced by at least 75 percent from a 3 year average baseline established no earlier than the 1987 calendar year, or for the time period from startup of the process until the present in which the PMPU was operational and data are available, whichever is the lesser time period. If a time period less than 3 years is used to set the baseline, the data must represent at least 1 year's worth of data. For any reduction in the HAP factor achieved by reducing a HAP that is also a VOC, an equivalent reduction in the VOC factor is also required. For any reduction in the HAP factor that is achieved by reducing a HAP that is not a VOC, the VOC factor may not be increased.

(3) Both requirements specified in paragraphs (e)(3)(i) and (ii) of this section are met.

(i) The production-indexed HAP consumption factor (kg HAP consumed/kg produced) shall be reduced by at least 50 percent from a 3-year average baseline established no earlier than the 1987 calendar year, or for the time period from startup of the process until the present in which the PMPU was operational and data are available, whichever is less. If a time period less than 3 years is used to set the baseline, the data must represent at least 1 year's worth of data. For any reduction in the HAP factor achieved by reducing a HAP that is also a VOC, an equivalent reduction in the VOC factor is also required. For any reduction in the HAP factor that is achieved by reducing a HAP that is not a VOC, the VOC factor may not be increased.

(ii) The total PMPU HAP emissions shall be reduced by an amount, in kg/yr, that, when divided by the annual production rate, in kg/yr, and added to the reduction of the production-indexed HAP consumption factor, in kg/kg, yields a value of at least 75 percent of the average baseline HAP production-indexed consumption factor established according to paragraph (e)(3)(i) of this section according to the equation provided in §63.1257(f)(2)(ii)(A). The total PMPU VOC emissions shall be reduced by an amount calculated according to the equation provided in

§63.1257(f)(2)(ii)(B). The annual reduction in HAP and VOC air emissions must be due to the use of the following control devices:

(A) Combustion control devices such as incinerators, flares or process heaters.

(B) Control devices such as condensers and carbon adsorbers whose recovered product is destroyed or shipped offsite for destruction.

(C) Any control device that does not ultimately allow for recycling of material back to the PMPU.

(D) Any control device for which the owner or operator can demonstrate that the use of the device in controlling HAP emissions will have no effect on the production-indexed consumption factor for the PMPU.

(4) The owner or operator may comply with the requirements in either paragraph (e)(2) or (3) of this section for a series of processes, including situations where multiple processes are merged, subject to the following conditions:

(i) The baseline period shall be a single year beginning no earlier than the 1992 calendar year.

(ii) The term “PMPU” shall have the meaning provided in §63.1251 except that the baseline and modified PMPU may include multiple processes (i.e., precursors, active ingredients, and final dosage form) if the owner or operator demonstrates to the satisfaction of the Administrator that the multiple processes were merged after the baseline period into an existing process or processes.

(iii) Nondedicated formulation and solvent recovery processes may not be merged with any other processes.

(f) *Control requirements for certain liquid streams in open systems within a PMPU.* (1) The owner or operator shall comply with the provisions of Table 5 of this subpart, for each item of equipment meeting all the criteria specified in paragraphs (f)(2) through (4) and either paragraph (f)(5)(i) or (ii) of this section.

(2) The item of equipment is of a type identified in Table 5 of this subpart;

(3) The item of equipment is part of a PMPU, as defined in §63.1251;

(4) The item of equipment is controlled less stringently than in Table 5 of this subpart and the item of equipment is not otherwise exempt from controls by the provisions of this subpart or subpart A of this part; and

(5) The item of equipment:

(i) Is a drain, drain hub, manhole, lift station, trench, pipe, or oil/water separator that conveys water with an annual average concentration greater than or equal to 1,300 parts per million by weight (ppmw) of partially soluble HAP compounds; or an annual average concentration greater than or equal to 5,200 ppmw of partially soluble and/or soluble HAP compounds. The annual average concentration shall be determined according to the procedures in §63.1257(e)(1)(ii).

(ii) Is a tank that receives one or more streams that contain water with an annual average concentration greater than or equal to 1,300 ppmw of partially soluble HAP compounds, or greater than or equal to 5,200 ppmw of total partially soluble and/or soluble HAP compounds. The owner or operator of the source shall determine the average concentration of the stream at the inlet to the tank and according to the procedures in §63.1257(e)(1)(ii).

(g) *Control requirements for halogenated vent streams that are controlled by combustion devices.* If a combustion device is used to comply with the provisions of §§63.1253 (storage tanks), 63.1254 (process vents), 63.1256(h) (wastewater vent streams) for a halogenated vent stream, then the vent stream shall be ducted to a halogen reduction device such as, but not limited to, a scrubber, before it is discharged to the atmosphere. The halogen reduction device must reduce emissions by the amounts specified in either paragraph (g)(1) or (2) of this section.

(1) A halogen reduction device after the combustion control device must reduce overall emissions of hydrogen halides and halogens, as defined in §63.1251, by 95 percent or to a concentration less than or equal to 20 ppmv.

(2) A halogen reduction device located before the combustion control device must reduce the halogen atom content of the vent stream to a concentration less than or equal to 20 ppmv.

(h) *Planned routine maintenance for centralized combustion control devices.* The owner or operator may operate non-dedicated PMPU's during periods of planned routine maintenance for CCCD in accordance with the provisions specified in paragraphs (h)(1) through (6) of this section.

(1) For equipment leaks and wastewater emissions that normally are controlled by the CCCD, if any, the owner or operator must continue to comply with the requirements in §§63.1255(b)(4)(ii) and 63.1256(h), respectively, using other control devices during the planned routine maintenance period for the CCCD.

(2) During the planned routine maintenance period, the owner or operator must route emissions from process vents with organic HAP emissions greater than 15 pounds per day (lb/day) through a closed-vent system to a condenser that meets the conditions specified in paragraphs (h)(2)(i) through (iii) of this section.

(i) The outlet gas temperature must be less than -50°C (-58°F) when the emission stream contains organic HAP with a partial pressure greater than 20 kPa (2.9 psia).

(ii) The outlet gas temperature must be less than -5°C (23°F) when the emission stream contains organic HAP with a partial pressure less than or equal to 20 kPa (2.9 psia).

(iii) The HAP partial pressures in paragraphs (h)(2)(i) and (ii) of this section must be determined at 25 °C.

(3) The owner or operator must route HCl emissions from process vents with HCl emissions greater than 15 lb/day through a closed-vent system to a caustic scrubber, and the pH of the scrubber effluent must be maintained at or above 9.

(4) For the purposes of the emission calculations required in paragraphs (h)(2) and (3) of this section, the term “process vent” shall mean each vent from a unit operation. The emission calculation shall not be performed on the aggregated emission stream from multiple unit operations that are manifolded together into a common header. Once an affected process vent has been controlled in accordance with this section, it is no longer subject to the requirements of this section or §63.1254 during the routine maintenance period.

(5) The total period of planned routine maintenance, during which non-dedicated PMPU's that are normally controlled by the CCCD continue to operate, and process vent emissions are controlled as specified in paragraphs (h)(2) and (3) of this section, must not exceed 240 hours in any 365-day period.

(6) While being controlled as specified in paragraphs (h)(2) and (3) of this section, the process vents may not be used in emissions averaging.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52600, Aug. 29, 2000; 66 FR 40131, Aug. 2, 2001]

§63.1253 Standards: Storage tanks.

(a) Except as provided in paragraphs (d), (e), and (f) of this section, the owner or operator of a storage tank meeting the criteria of paragraph (a)(1) of this section is subject to the requirements of paragraph (b) of this section. Except as provided in paragraphs (d), (e), and (f) of this section, the owner or operator of a storage tank meeting the criteria of paragraph (a)(2) of this section is subject to the requirements of paragraph (c) of this section. Compliance with the provisions of paragraphs (b) and (c) of this section is demonstrated using the initial compliance procedures in §63.1257(c) and the monitoring requirements in §63.1258.

(1) A storage tank with a design capacity greater than or equal to 38 m³ but less than 75 m³ storing a liquid for which the maximum true vapor pressure of total HAP is greater than or equal to 13.1 kPa.

(2) A storage tank with a design capacity greater than or equal to 75 m³ storing a liquid for which the maximum true vapor pressure of total HAP is greater than or equal to 13.1 kPa.

(b) The owner or operator of a storage tank shall equip the affected storage tank with either a fixed roof with internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, or a closed-vent system meeting the conditions of §63.1252(b) with a control device that meets any of the following conditions:

- (1) Reduces inlet emissions of total HAP by 90 percent by weight or greater;
- (2) Reduces emissions to outlet concentrations less than or equal to 20 ppmv as TOC and less than or equal to 20 ppmv as hydrogen halides and halogens;
- (3) Is an enclosed combustion device that provides a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C;
- (4) Is a flare that meets the requirements of §63.11(b); or
- (5) Is a control device specified in §63.1257(a)(4).

(c) The owner or operator of a storage tank shall equip the affected storage tank with either a fixed roof with internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, or a closed-vent system meeting the conditions of §63.1252(b) with a control device that meets any of the following conditions:

(1) Reduces inlet emissions of total HAP as specified in paragraph (c)(1) (i) or (ii) of this section:

(i) By 95 percent by weight or greater; or (ii) If the owner or operator can demonstrate that a control device installed on a storage tank on or before April 2, 1997 is designed to reduce inlet emissions of total HAP by greater than or equal to 90 percent by weight but less than 95 percent by weight, then the control device is required to be operated to reduce inlet emissions of total HAP by 90 percent or greater.

(2) Reduces emissions to outlet concentrations less than or equal to 20 ppmv as TOC and less than or equal to 20 ppmv as hydrogen halides and halogens;

(3) Is an enclosed combustion device that provides a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C;

(4) Is a flare that meets the requirements of §63.11(b); or

(5) Is a control device specified in §63.1257(a)(4).

(d) As an alternative standard, the owner or operator of an existing or new affected source may comply with the storage tank standards by routing storage tank vents to a combustion control device achieving an outlet TOC concentration, as calibrated on methane or the predominant HAP, of 20 ppmv or less, and an outlet concentration of hydrogen halides and halogens of 20 ppmv or less. If the owner or operator is routing emissions to a noncombustion control device, it must achieve an outlet TOC concentration, as calibrated on methane or the predominant HAP, of 50 ppmv or less, and an outlet concentration of hydrogen halides and halogens of 50 ppmv or less. Compliance with the outlet concentrations shall be determined by the initial compliance procedures of §63.1257(c)(4) and the continuous emission monitoring requirements of §63.1258(b)(5).

(e) *Planned routine maintenance.* The specifications and requirements in paragraphs (b) through (d) of this section for control devices do not apply during periods of planned routine maintenance. Periods of planned routine maintenance of the control devices (including CCCD subject to §63.1252(h)), during which the control device does not meet the specifications of paragraphs (b) through (d) of this section, as applicable, shall not exceed 240 hours in any 365-day period. The owner or operator may submit an application to the Administrator requesting an extension of this time limit to a total of 360 hours in any 365-day period. The application must explain why the extension is needed, it must specify that no material will be added to the storage tank between the time the 240-hour limit is exceeded and the control device is again operational, and it must be submitted at least 60 days before the 240-hour limit will be exceeded.

(f) *Vapor balancing alternative.* As an alternative to the requirements in paragraphs (b) and (c) of this section, the owner or operator of an existing or new affected source may implement vapor balancing in accordance with paragraphs (f)(1) through (7) of this section.

(1) The vapor balancing system must be designed and operated to route organic HAP vapors displaced from loading of the storage tank to the railcar or tank truck from which the storage tank is filled.

(2) Tank trucks and railcars must have a current certification in accordance with the U.S. Department of Transportation (DOT) pressure test requirements of 49 CFR part 180 for tank trucks and 49 CFR 173.31 for railcars.

(3) Hazardous air pollutants must only be unloaded from tank trucks or railcars when vapor collection systems are connected to the storage tank's vapor collection system.

(4) No pressure relief device on the storage tank, or on the railcar, or tank truck shall open during loading or as a result of diurnal temperature changes (breathing losses).

(5) Pressure relief devices on affected storage tanks must be set to no less than 2.5 psig at all times to prevent breathing losses. The owner or operator shall record the setting as specified in §63.1259(b)(12) and comply with the requirements for each pressure relief valve in paragraphs (f)(5)(i) through (iii) of this section:

(i) The pressure relief valve shall be monitored quarterly using the method described in §63.180(b).

(ii) An instrument reading of 500 ppmv or greater defines a leak.

(iii) When a leak is detected, it shall be repaired as soon as practicable, but no later than 5 days after it is detected, and the owner or operator shall comply with the recordkeeping requirements of §63.1255(g)(4)(i) through (iv).

(6) Railcars or tank trucks that deliver HAP to an affected storage tank must be reloaded or cleaned at a facility that utilizes one of the control techniques in paragraph (f)(6)(i) through (ii) of this section:

(i) The railcar or tank truck must be connected to a closed-vent system with a control device that reduces inlet emissions of HAP by 90 percent by weight or greater; or

(ii) A vapor balancing system designed and operated to collect organic HAP vapor displaced from the tank truck or railcar during reloading must be used to route the collected HAP vapor to the storage tank from which the liquid being transferred originated.

(7) The owner or operator of the facility where the railcar or tank truck is reloaded or cleaned must comply with the requirements in paragraph (f)(7)(i) through (iii) of this section:

(i) Submit to the owner or operator of the affected storage tank and to the Administrator a written certification that the reloading or cleaning facility will meet the requirements of this section. The certifying entity may revoke the written certification by sending a written statement to the owner or operator of the affected storage tank giving at least 90 days notice that the certifying entity is rescinding acceptance of responsibility for compliance with the requirements of this paragraph (b)(7).

(ii) If complying with paragraph (f)(6)(i) of this section, demonstrate initial compliance in accordance with §63.1257(c), demonstrate continuous compliance in accordance with §63.1258, keep records as specified in §63.1259, and prepare reports as specified in §63.1260.

(iii) If complying with paragraph (f)(6)(ii) of this section, keep records of:

(A) The equipment to be used and the procedures to be followed when reloading the railcar or tank truck and displacing vapors to the storage tank from which the liquid originates, and

(B) Each time the vapor balancing system is used to comply with paragraph (f)(6)(ii) of this section.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52601, Aug. 29, 2000; 66 FR 40132, Aug. 2, 2001; 70 FR 25669, May 13, 2005]

§63.1254 Standards: Process vents.

(a) *Existing sources.* For each process, the owner or operator of an existing affected source must comply with the requirements in paragraphs (a)(1) and (3) of this section or paragraphs (a)(2) and (3) of this section. Initial compliance with the required emission limits or reductions in paragraphs (a)(1) through (3) of this section is demonstrated in accordance with the initial compliance procedures described in §63.1257(d), and continuous compliance is demonstrated in accordance with the monitoring requirements described in §63.1258.

(1) *Process-based emission reduction requirement.* (i) Uncontrolled HAP emissions from the sum of all process vents within a process that are not subject to the requirements of paragraph (a)(3) of this section shall be reduced by 93 percent or greater by weight, or as specified in paragraph (a)(1)(ii) of this section. Notification of changes in the compliance method shall be reported according to the procedures in §63.1260(h).

(ii) Any one or more vents within a process may be controlled in accordance with any of the procedures in paragraphs (a)(1)(ii)(A) through (D) of this section. All other vents within the process must be controlled as specified in paragraph (a)(1)(i) of this section.

(A) To outlet concentrations less than or equal to 20 ppmv as TOC and less than or equal to 20 ppmv as hydrogen halides and halogens;

(B) By a flare that meets the requirements of §63.11(b);

(C) By a control device specified in §63.1257(a)(4); or

(D) In accordance with the alternative standard specified in paragraph (c) of this section.

(2) *Process-based annual mass limit.* (i) Actual HAP emissions from the sum of all process vents within a process must not exceed 900 kilograms (kg) in any 365-day period.

(ii) Actual HAP emissions from the sum of all process vents within processes complying with paragraph (a)(2)(i) of this section are limited to a maximum of 1,800 kg in any 365-day period.

(iii) Emissions from vents that are subject to the requirements of paragraph (a)(3) of this section and emissions from vents that are controlled in accordance with the procedures in paragraph (c) of this section may be excluded from the sums calculated in paragraphs (a)(2)(i) and (ii) of this section.

(iv) The owner or operator may switch from compliance with paragraph (a)(2) of this section to compliance with paragraph (a)(1) of this section only after at least 1 year of operation in compliance with paragraph (a)(2) of this section. Notification of such a change in the compliance method shall be reported according to the procedures in §63.1260(h).

(3) *Individual vent emission reduction requirements.* (i) Except as provided in paragraph (a)(3)(ii) of this section, uncontrolled HAP emissions from a process vent must be reduced by 98 percent or in accordance with any of the procedures in paragraphs (a)(1)(ii)(A) through (D) of this section if the uncontrolled HAP emissions from the vent exceed 25 tons per year, and the flow-weighted average flowrate (FRA) calculated using Equation 1 of this subpart is less than or equal to the flowrate index (FRI) calculated using Equation 2 of this subpart.

$$FRA = \frac{\sum_{i=1}^n (D_i)(FR_i)}{\sum_{i=1}^n (D_i)} \quad (Eq. 1)$$

$$FRI = 0.02 * (HL) - 1,000 \quad (Eq. 2)$$

Where:

FR_a = flow-weighted average flowrate for the vent, scfm

D_i = duration of each emission event, min

FR_i = flowrate of each emission event, scfm

n = number of emission events

FRI = flowrate index, scfm

HL = annual uncontrolled HAP emissions, lb/yr, as defined in §63.1251

(ii) *Grandfathering provisions.* As an alternative to the requirements in paragraph (a)(3)(i) of this section, the owner or operator may comply with the provisions in paragraph (a)(3)(ii)(A), (B), or (C) of this section, if applicable.

(A) *Control device operation.* If the owner or operator can demonstrate that a process vent is controlled by a control device meeting the criteria specified in paragraph (a)(3)(ii)(A)(1) of this section, then the control device is required to be operated according to paragraphs (a)(3)(ii)(A)(2), (3), and (4) of this section:

(1) The control device was installed on any process vent that met the conditions of paragraph (a)(3)(i) of this section on or before April 2, 1997, and was operated to reduce uncontrolled emissions of total HAP by greater than or equal to 93 percent by weight, but less than 98 percent by weight;

(2) The device must be operated to reduce inlet emissions of total HAP by 93 percent or by the percent reduction specified for that control device in any preconstruction permit issued pursuant to regulations approved or promulgated through rulemaking under title I (including parts C or D) of the Clean Air Act, whichever is greater;

(3) The device must be replaced or upgraded to achieve at least 98 percent reduction of HAP or meet any of the conditions specified in paragraphs (a)(1)(ii)(A) through (D) of this section upon reconstruction or replacement.

(4) The device must be replaced or upgraded to achieve at least 98 percent reduction of HAP or meet any of the conditions specified in paragraphs (a)(1)(ii)(A) through (D) of this section by April 2, 2007, or 15 years after issuance of the preconstruction permit, whichever is later.

(B) *Process operations.* If a process meets all of the conditions specified in paragraphs (a)(3)(ii)(B)(1) through (3) of this section, the required level of control for the process is the level that was achieved on or before April 2, 1997. This level of control is demonstrated using

the same procedures that are used to demonstrate compliance with paragraph (a)(1) of this section.

(1) At least one vent in the process met the conditions of paragraph (a)(3)(i) of this section on or before April 2, 1997; and

(2) The overall control for the process on or before April 2, 1997 was greater than or equal to 93 percent by weight, but less than 98 percent by weight; and

(3) The production-indexed HAP consumption factor for the 12-month period in which the process was operated prior to the compliance date is less than one-half of the 3-year average baseline value established no earlier than the 1987 through 1989 calendar years.

(C) *Hydrogenation vents.* Processes meeting the conditions of paragraphs (a)(3)(ii)(C)(1) through (3) of this section are required to be operated to maintain the level of control achieved on or before April 2, 1997. For all other processes meeting the conditions of paragraph (a)(3)(ii)(C)(3) of this section, uncontrolled HAP emissions from the sum of all process vents within the process must be reduced by 95 percent or greater by weight.

(1) Processes containing a process vent that met the conditions of paragraph (a)(3)(i) of this section on or before April 2, 1997; and

(2) Processes that are controlled to greater than or equal to 93 percent by weight, but less than 98 percent by weight; and

(3) Processes with a hydrogenation vent that, in conjunction with all other process vents from the process that do not meet the conditions of paragraph (a)(3)(i) of this section, cannot meet the requirements of paragraph (a)(1) or (2) of this section.

(4) *Planned routine maintenance.* For each PMPU that is controlled with a CCCD, the owner or operator must comply with the provisions specified in either paragraph (a)(4)(i), (ii), or (iii) of this section during periods of planned routine maintenance of the CCCD. The owner or operator is not required to comply with the same provision for all of the PMPU's controlled by the CCCD.

(i) Shutdown the affected process.

(ii) Comply with the requirements of paragraphs (a)(1) through (3) of this section by using other means.

(iii) For a non-dedicated PMPU, implement the procedures described in paragraphs (a)(4)(iii)(A) through (C) of this section for those process vents that are normally controlled by the CCCD. This option is not available for process vents from dedicated PMPU's.

(A) If the owner or operator uses a CCCD to comply with the 93 percent reduction requirement in paragraph (a)(1)(i) or (ii) of this section, the outlet concentration limit in paragraph (a)(1)(ii)(A) of this section, the alternative standard as specified in paragraphs (a)(1)(ii)(D) and

(c) of this section, or the annual mass limit in paragraph (a)(2) of this section, implement the provisions in §63.1252(h) during planned routine maintenance of the CCCD.

(B) If the owner or operator reduces HAP emissions from process vents by using a CCCD that is also a control device specified in §63.1257(a)(4), implement the provisions in §63.1252(h) during planned routine maintenance of the CCCD.

(C) If the owner or operator uses a CCCD to reduce emissions from a process vent subject to paragraph (a)(3) of this section, implement the planned routine maintenance provisions in §63.1252(h) for that vent only if the reason the planned routine maintenance is needed, and the reason it cannot be performed at a time when the vent subject to paragraph (a)(3) of this section is not operating, has been described in the Notification of Compliance Status Report or a periodic report submitted before the planned routine maintenance event.

(b) *New sources.* (1) Except as provided in paragraph (b)(2) of this section, uncontrolled HAP emissions from the sum of all process vents within a process at a new affected source shall be reduced by 98 percent or greater by weight or controlled in accordance with any of requirements of paragraphs (a)(1)(ii)(A) through (D) of this section. Initial compliance with the required emission limit or reduction is demonstrated in accordance with the initial compliance procedures in §63.1257(d), and continuous compliance is demonstrated in accordance with the monitoring requirements described in §63.1258.

(2) *Annual mass limit.* The actual HAP emissions from the sum of all process vents for which the owner or operator is not complying with paragraph (b)(1) of this section are limited to 900 kg in any 365-day period.

(c) *Alternative standard.* As an alternative standard, the owner or operator of an existing or new affected source may comply with the process vent standards by routing vents from a process to a combustion control device achieving an outlet TOC concentration, as calibrated on methane or the predominant HAP, of 20 ppmv or less, and an outlet concentration of hydrogen halides and halogens of 20 ppmv or less. If the owner or operator is routing emissions to a noncombustion control device, it must achieve an outlet TOC concentration, as calibrated on methane or the predominant HAP, of 50 ppmv or less, and an outlet concentration of hydrogen halides and halogens of 50 ppmv or less. Any process vents within a process that are not routed to this control device must be controlled in accordance with the provisions of paragraph (a) or (b) of this section, as applicable. Initial compliance with the outlet concentrations is demonstrated in accordance with the initial compliance procedures described in §63.1257(d)(1)(iv), and continuous compliance is demonstrated in accordance with the emission monitoring requirements described in §63.1258(b)(5).

[65 FR 52601, Aug. 29, 2000, as amended at 66 FR 40132, Aug. 2, 2001]

§63.1255 Standards: Equipment leaks.

(a) *General equipment leak requirements.* (1) The provisions of this section apply to pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves

or lines, valves, connectors, instrumentation systems, control devices, and closed-vent systems required by this section that are intended to operate in organic hazardous air pollutant service 300 hours or more during the calendar year within a source subject to the provisions of this subpart.

(2) *Consistency with other regulations.* After the compliance date for a process, equipment subject to both this section and either of the following will be required to comply only with the provisions of this subpart:

(i) 40 CFR part 60.

(ii) 40 CFR part 61.

(3) [Reserved]

(4) The provisions in §63.1(a)(3) of subpart A of this part do not alter the provisions in paragraph (a)(2) of this section.

(5) Lines and equipment not containing process fluids are not subject to the provisions of this section. Utilities, and other nonprocess lines, such as heating and cooling systems which do not combine their materials with those in the processes they serve, are not considered to be part of a process.

(6) The provisions of this section do not apply to bench-scale processes, regardless of whether the processes are located at the same plant site as a process subject to the provisions of this subpart.

(7) Equipment to which this section applies shall be identified such that it can be distinguished readily from equipment that is not subject to this section. Identification of the equipment does not require physical tagging of the equipment. For example, the equipment may be identified on a plant site plan, in log entries, or by designation of process boundaries by some form of weatherproof identification. If changes are made to the affected source subject to the leak detection requirements, equipment identification for each type of component shall be updated, if needed, within 90 calendar days or by the next Periodic Report following the end of the monitoring period for that component, whichever is later.

(8) Equipment that is in vacuum service is excluded from the requirements of this section.

(9) Equipment that is in organic HAP service, but is in such service less than 300 hours per calendar year, is excluded from the requirements of this section if it is identified as required in paragraph (g)(9) of this section.

(10) When each leak is detected by visual, audible, or olfactory means, or by monitoring as described in §63.180(b) or (c), the following requirements apply:

(i) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(ii) The identification on a valve in light liquid or gas/vapor service may be removed after it has been monitored as specified in paragraph (e)(7)(iii) of this section, and no leak has been detected during the follow-up monitoring.

(iii) The identification on equipment, except on a valve in light liquid or gas/vapor service, may be removed after it has been repaired.

(11) Except as provided in paragraph (a)(11)(i) of this section, all terms in this subpart that define a period of time for completion of required tasks (e.g., weekly, monthly, quarterly, annual) refer to the standard calendar periods unless specified otherwise in the section or paragraph that imposes the requirement.

(i) If the initial compliance date does not coincide with the beginning of the standard calendar period, an owner or operator may elect to utilize a period beginning on the compliance date, or may elect to comply in accordance with the provisions of paragraph (a)(11)(ii) or (iii) of this section.

(ii) Time periods specified in this subpart for completion of required tasks may be changed by mutual agreement between the owner or operator and the Administrator, as specified in subpart A of this part. For each time period that is changed by agreement, the revised period shall remain in effect until it is changed. A new request is not necessary for each recurring period.

(iii) Except as provided in paragraph (a)(11)(i) or (ii) of this section, where the period specified for compliance is a standard calendar period, if the initial compliance date does not coincide with the beginning of the calendar period, compliance shall be required according to the schedule specified in paragraph (a)(11)(iii)(A) or (B) of this section, as appropriate.

(A) Compliance shall be required before the end of the standard calendar period within which the initial compliance date occurs if there remain at least 3 days for tasks that must be performed weekly, at least 2 weeks for tasks that must be performed monthly, at least 1 month for tasks that must be performed each quarter, or at least 3 months for tasks that must be performed annually; or

(B) In all other cases, compliance shall be required before the end of the first full standard calendar period after the period within which the initial compliance date occurs.

(iv) In all instances where a provision of this subpart requires completion of a task during each of multiple successive periods, an owner or operator may perform the required task at any time during each period, provided the task is conducted at a reasonable interval after completion of the task during the previous period.

(12) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this section to fail to take action

to repair the leaks within the specified time. If action is taken to repair the leaks within the specified time, failure of that action to successfully repair the leak is not a violation of this section. However, if the repairs are unsuccessful, a leak is detected and the owner or operator shall take further action as required by applicable provisions of this section.

(b) *References.* (1) The owner or operator of a source subject to this section shall comply with the provisions of subpart H of this part, as specified in paragraphs (b)(2) through (4) of this section. The term “process unit” as used in subpart H of this part shall be considered to be defined the same as “group of processes” for sources subject to this subpart GGG. The term “fuel gas system,” as used in subpart H of this part, shall not apply for the purposes of this subpart GGG.

(2) Sections 63.160, 63.161, 63.162, 63.163, 63.167, 63.168, 63.170, 63.173, 63.175, 63.176, 63.181, and 63.182 shall not apply for the purposes of this subpart GGG. The owner or operator shall comply with the provisions specified in paragraphs (b)(2)(i) through (viii) of this section.

(i) Sections 63.160 and 63.162 shall not apply; instead, the owner or operator shall comply with paragraph (a) of this section;

(ii) Section 63.161 shall not apply; instead, the owner or operator shall comply with §63.1251;

(iii) Sections 63.163 and 63.173 shall not apply; instead, the owner or operator shall comply with paragraph (c) of this section;

(iv) Section 63.167 shall not apply; instead, the owner or operator shall comply with paragraph (d) of this section;

(v) Section 63.168 shall not apply; instead, the owner or operator shall comply with paragraph (e) of this section;

(vi) Section 63.170 shall not apply; instead, the owner or operator shall comply with §63.1254;

(vii) Section 63.181 shall not apply; instead, the owner or operator shall comply with paragraph (g) of this section; and

(viii) Section 63.182 shall not apply; instead, the owner or operator shall comply with paragraph (h) of this section.

(3) The owner or operator shall comply with §§63.164, 63.165, 63.166, 63.169, 63.177, and 63.179 in their entirety, except that when these sections reference other sections of subpart H of this part, the references shall mean the sections specified in paragraphs (b)(2) and (4) of this section. Section 63.164 applies to compressors. Section 63.165 applies to pressure relief devices in gas/vapor service. Section 63.166 applies to sampling connection systems. Section 63.169 applies to pumps, valves, connectors, and agitators in heavy liquid service; instrumentation systems; and pressure relief devices in liquid service. Section 63.177 applies to general

alternative means of emission limitation. Section 63.179 applies to alternative means of emission limitation for enclosed-vented process units.

(4) The owner or operator shall comply with §§63.171, 63.172, 63.174, 63.178, and 63.180, except as specified in paragraphs (b)(4)(i) through (vi) of this section.

(i) Section 63.171 shall apply, except §63.171(a) shall not apply. Instead, delay of repair of equipment for which leaks have been detected is allowed if one of the conditions in paragraphs (b)(4)(i)(A) through (B) exists:

(A) The repair is technically infeasible without a process shutdown. Repair of this equipment shall occur by the end of the next scheduled process shutdown.

(B) The owner or operator determines that repair personnel would be exposed to an immediate danger if attempting to repair without a process shutdown. Repair of this equipment shall occur by the end of the next scheduled process shutdown.

(ii) Section 63.172 shall apply for closed-vent systems used to comply with this section, and for control devices used to comply with this section only, except:

(A) Section 63.172(k) and (l) shall not apply. The owner or operator shall instead comply with paragraph (f) of this section.

(B) Owners or operators may, instead of complying with the provisions of §63.172(f), design a closed-vent system to operate at a pressure below atmospheric pressure. The system shall be equipped with at least one pressure gage or other pressure measurement device that can be read from a readily accessible location to verify that negative pressure is being maintained in the closed-vent system when the associated control device is operating.

(C) The requirements apply at all times, except as specified in §63.1250(g). The owner or operator may not comply with the planned routine maintenance provisions in §63.1252(h).

(iii) Section 63.174 shall apply except:

(A) Section 63.174(f), (g), and (h) shall not apply. Instead of §63.174(f), (g), and (h), the owner or operator shall comply with paragraph (f) of this section. Section 63.174(b)(3) shall not apply. Instead of §63.174(b)(3), the owner or operator shall comply with paragraphs (b)(4)(iii)(B) through (F) of this section.

(B) If the percent leaking connectors in a group of processes was greater than or equal to 0.5 percent during the initial monitoring period, monitoring shall be performed once per year until the percent leaking connectors is less than 0.5 percent.

(C) If the percent leaking connectors in the group of processes was less than 0.5 percent, but equal to or greater than 0.25 percent, during the initial or last required monitoring period, the owner or operator may elect to monitor once every 4 years. An owner or operator may comply

with the requirements of this paragraph by monitoring at least 40 percent of the connectors in the first 2 years and the remainder of the connectors within the next 2 years. The percent leaking connectors will be calculated for the total of all required monitoring performed during the 4-year period.

(D) Except as provided in paragraph (b)(4)(iii)(B) of this section, if leaking connectors comprise at least 0.5 percent but less than 1.0 percent of the connectors during the last monitoring period, the owner or operator shall monitor at least once every 2 years for the next monitoring period. At the end of that 2-year monitoring period, if the percent leaking connectors is greater than or equal to 0.5 percent, the owner or operator shall monitor once per year until the percent leaking connectors is less than 0.5 percent. If, at the end of a monitoring period, the percent leaking connectors is less than 0.5 percent, the owner or operator shall monitor in accordance with paragraph (b)(4)(iii)(C) or (F) of this section, as appropriate.

(E) If an owner or operator determines that 1 percent or greater of the connectors in a group of processes are leaking, the owner or operator shall monitor the connectors once per year. The owner or operator may elect to use the provisions of paragraph (b)(4)(iii)(C), (D), or (F) of this section, as appropriate, after a monitoring period in which less than 1 percent of the connectors are determined to be leaking.

(F) The owner or operator may elect to perform monitoring once every 8 years if the percent leaking connectors in the group of processes was less than 0.25 percent during the initial or last required monitoring period. An owner or operator shall monitor at least 50 percent of the connectors in the first 4 years and the remainder of the connectors within the next 4 years. If the percent leaking connectors in the first 4 years is equal to or greater than 0.35 percent, the monitoring program shall revert at that time to the appropriate monitoring frequency specified in paragraph (b)(4)(iii)(C), (D), or (E) of this section.

(iv) Section 63.178 shall apply except:

(A) Section 63.178(b), requirements for pressure testing, may be applied to all processes (not just batch processes) and to supply lines between storage and processing areas.

(B) For pumps, the phrase “at the frequencies specified in Table 1 of this subpart” in §63.178(c)(3)(iii) shall mean “quarterly” for the purposes of this subpart.

(v) Section 63.180 shall apply except §63.180(b)(4)(ii)(A) through (C) shall not apply. Instead, calibration gases shall be a mixture of methane and air at a concentration of approximately, but less than, 10,000 parts per million methane for agitators; 2,000 parts per million for pumps; and 500 parts per million for all other equipment, except as provided in §63.180(b)(4)(iii).

(vi) When §§63.171, 63.172, 63.174, 63.178, and 63.180 reference other sections in subpart H of this part, the references shall mean those sections specified in paragraphs (b)(2) and (b)(4)(i) through (v) of this section, as applicable.

(c) *Standards for pumps in light liquid service and agitators in gas/vapor service and in light liquid service.* (1) The provisions of this section apply to each pump that is in light organic HAP liquid service, and to each agitator in organic HAP gas/vapor service or in light organic HAP liquid service.

(2)(i) *Monitoring.* Each pump and agitator subject to this section shall be monitored quarterly to detect leaks by the method specified in §63.180(b) except as provided in §§63.177, 63.178, paragraph (f) of this section, and paragraphs (c)(5) through (9) of this section.

(ii) *Leak definition.* The instrument reading, as determined by the method as specified in §63.180(b), that defines a leak is:

(A) For agitators, an instrument reading of 10,000 parts per million or greater.

(B) For pumps, an instrument reading of 2,000 parts per million or greater.

(iii) *Visual Inspections.* Each pump and agitator shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump or agitator seal. If there are indications of liquids dripping from the pump or agitator seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (c)(2)(iii)(A) or (B) of this section prior to the next weekly inspection.

(A) The owner or operator shall monitor the pump or agitator by the method specified in §63.180(b). If the instrument reading indicates a leak as specified in paragraph (c)(2)(ii) of this section, a leak is detected.

(B) The owner or operator shall eliminate the visual indications of liquids dripping.

(3) *Repair provisions.* (i) When a leak is detected pursuant to paragraph (c)(2)(i), (c)(2)(iii)(A), (c)(5)(iv)(A), or (c)(5)(vi)(B) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in paragraph (b)(4)(i) of this section.

(ii) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. First attempts at repair include, but are not limited to, the following practices where practicable:

(A) Tightening of packing gland nuts.

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

(4) *Calculation of percent leakers.* (i) The owner or operator shall decide no later than the end of the first monitoring period what groups of processes will be developed. Once the owner or operator has decided, all subsequent percent calculations shall be made on the same basis.

(ii) If, calculated on a 1-year rolling average, the greater of either 10 percent or three of the pumps in a group of processes leak, the owner or operator shall monitor each pump once per

month, until the calculated 1-year rolling average value drops below 10 percent or three pumps, as applicable.

(iii) The number of pumps in a group of processes shall be the sum of all the pumps in organic HAP service, except that pumps found leaking in a continuous process within 1 quarter after startup of the pump shall not count in the percent leaking pumps calculation for that one monitoring period only.

(iv) Percent leaking pumps shall be determined by the following Equation 3:

$$\%P_L = [(P_L - P_s) / (P_T - P_s)] \times 100 \text{ (Eq. 3)}$$

Where:

$\%P_L$ = percent leaking pumps

P_L = number of pumps found leaking as determined through periodic monitoring as required in paragraphs (c)(2)(i) and (ii) of this section.

P_T = total pumps in organic HAP service, including those meeting the criteria in paragraphs (c)(5) and (6) of this section.

P_s = number of pumps in a continuous process leaking within 1 quarter of startup during the current monitoring period.

(5) *Exemptions.* Each pump or agitator equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraphs (c)(1) through (c)(4)(iii) of this section, provided the following requirements are met:

(i) Each dual mechanical seal system is:

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

(B) Equipped with a barrier fluid degassing reservoir that is connected by a closed-vent system to a control device that complies with the requirements of paragraph (b)(4)(ii) of this section; or

(C) Equipped with a closed-loop system that purges the barrier fluid into a process stream.

(ii) The barrier fluid is not in light liquid service.

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

(iv) Each pump/agitator is checked by visual inspection each calendar week for indications of liquids dripping from the pump/agitator seal. If there are indications of liquids dripping from the

pump or agitator seal at the time of the weekly inspection, the owner or operator shall follow the procedures specified in either paragraph (c)(5)(iv)(A) or (B) of this section prior to the next required inspection.

(A) The owner or operator shall monitor the pump or agitator using the method specified in §63.180(b) to determine if there is a leak of organic HAP in the barrier fluid. If the instrument reading indicates a leak, as specified in paragraph (c)(2)(ii) of this section, a leak is detected.

(B) The owner or operator shall eliminate the visual indications of liquids dripping.

(v) Each sensor as described in paragraph (c)(5)(iii) of this section is observed daily or is equipped with an alarm unless the pump is located within the boundary of an unmanned plant site.

(vi)(A) The owner or operator determines, based on design considerations and operating experience, criteria applicable to the presence and frequency of drips and to the sensor that indicate failure of the seal system, the barrier fluid system, or both.

(B) If indications of liquids dripping from the pump/agitator seal exceed the criteria established in paragraph (c)(5)(vi)(A) of this section, or if, based on the criteria established in paragraph (c)(5)(vi)(A) of this section, the sensor indicates failure of the seal system, the barrier fluid system, or both, a leak is detected.

(vii) When a leak is detected pursuant to paragraph (c)(5)(iv)(A) or (B) of this section, the leak must be repaired as specified in paragraph (c)(3) of this section.

(6) Any pump/agitator that is designed with no externally actuated shaft penetrating the pump/agitator housing is exempt from the requirements of paragraphs (c)(1) through (3) of this section.

(7) Any pump/agitator equipped with a closed-vent system capable of capturing and transporting any leakage from the seal or seals back to the process or to a control device that complies with the requirements of paragraph (b)(4)(ii) of this section is exempt from the requirements of paragraphs (c)(2) through (5) of this section.

(8) Any pump/agitator that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (c)(2)(iii) and (c)(5)(iv) of this section, and the daily requirements of paragraph (c)(5)(v) of this section, provided that each pump/agitator is visually inspected as often as practicable and at least monthly.

(9) If more than 90 percent of the pumps in a group of processes meet the criteria in either paragraph (c)(5) or (6) of this section, the group of processes is exempt from the requirements of paragraph (c)(4) of this section.

(d) *Standards: Open-ended valves or lines.* (1)(i) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §63.177 and paragraphs (d)(4) through (6) of this section.

(ii) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line, or during maintenance or repair. The cap, blind flange, plug, or second valve shall be in place within 1 hour of cessation of operations requiring process fluid flow through the open-ended valve or line, or within 1 hour of cessation of maintenance or repair. The owner or operator is not required to keep a record documenting compliance with the 1-hour requirement.

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

(3) When a double block and bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (d)(1) of this section at all other times.

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

(5) Open-ended valves or lines containing materials which would autocatalytically polymerize are exempt from the requirements of paragraphs (d)(1) through (d)(3) of this section.

(6) Open-ended valves or lines containing materials which could cause an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (d)(1) through (d)(3) of this section are exempt from the requirements of paragraphs (d)(1) through (d)(3) of this section.

(e) *Standards: Valves in gas/vapor service and in light liquid service.* (1) The provisions of this section apply to valves that are either in gas organic HAP service or in light liquid organic HAP service.

(2) For existing and new affected sources, all valves subject to this section shall be monitored, except as provided in paragraph (f) of this section and in §63.177, by no later than 1 year after the compliance date.

(3) *Monitoring.* The owner or operator of a source subject to this section shall monitor all valves, except as provided in paragraph (f) of this section and in §63.177, at the intervals specified in paragraph (e)(4) of this section and shall comply with all other provisions of this section, except as provided in paragraph (b)(4)(i) of this section, §§63.178 and 63.179.

(i) The valves shall be monitored to detect leaks by the method specified in §63.180(b).

(ii) An instrument reading of 500 parts per million or greater defines a leak.

(4) *Subsequent monitoring frequencies.* After conducting the initial survey required in paragraph (e)(2) of this section, the owner or operator shall monitor valves for leaks at the intervals specified below:

(i) For a group of processes with 2 percent or greater leaking valves, calculated according to paragraph (e)(6) of this section, the owner or operator shall monitor each valve once per month, except as specified in paragraph (e)(9) of this section.

(ii) For a group of processes with less than 2 percent leaking valves, the owner or operator shall monitor each valve once each quarter, except as provided in paragraphs (e)(4)(iii) through (e)(4)(v) of this section.

(iii) For a group of processes with less than 1 percent leaking valves, the owner or operator may elect to monitor each valve once every 2 quarters.

(iv) For a group of processes with less than 0.5 percent leaking valves, the owner or operator may elect to monitor each valve once every 4 quarters.

(v) For a group of processes with less than 0.25 percent leaking valves, the owner or operator may elect to monitor each valve once every 2 years.

(5) *Calculation of percent leakers.* For a group of processes to which this subpart applies, an owner or operator may choose to subdivide the valves in the applicable group of processes and apply the provisions of paragraph (e)(4) of this section to each subgroup. If the owner or operator elects to subdivide the valves in the applicable group of processes, then the provisions of paragraphs (e)(5)(i) through (e)(5)(viii) of this section apply.

(i) The overall performance of total valves in the applicable group of processes must be less than 2 percent leaking valves, as detected according to paragraphs (e)(3) (i) and (ii) of this section and as calculated according to paragraphs (e)(6) (ii) and (iii) of this section.

(ii) The initial assignment or subsequent reassignment of valves to subgroups shall be governed by the provisions of paragraphs (e)(5)(ii) (A) through (C) of this section.

(A) The owner or operator shall determine which valves are assigned to each subgroup. Valves with less than 1 year of monitoring data or valves not monitored within the last 12 months must be placed initially into the most frequently monitored subgroup until at least 1 year of monitoring data has been obtained.

(B) Any valve or group of valves can be reassigned from a less frequently monitored subgroup to a more frequently monitored subgroup provided that the valves to be reassigned were monitored during the most recent monitoring period for the less frequently monitored subgroup. The monitoring results must be included with the less frequently monitored subgroup's monitoring event and associated next percent leaking valves calculation for that group.

(C) Any valve or group of valves can be reassigned from a more frequently monitored subgroup to a less frequently monitored subgroup provided that the valves to be reassigned have not leaked for the period of the less frequently monitored subgroup (e.g., for the last 12 months, if the valve or group of valves is to be reassigned to a subgroup being monitored annually). Nonrepairable valves may not be reassigned to a less frequently monitored subgroup.

(iii) The owner or operator shall determine every 6 months if the overall performance of total valves in the applicable group of processes is less than 2 percent leaking valves and so indicate the performance in the next periodic report. If the overall performance of total valves in the applicable group of processes is 2 percent leaking valves or greater, the owner or operator shall revert to the program required in paragraphs (e)(2) through (e)(4) of this section. The overall performance of total valves in the applicable group of processes shall be calculated as a weighted average of the percent leaking valves of each subgroup according to the following Equation 4:

$$\%V_{LO} = \frac{\sum_{i=1}^n (\%V_{Li} \times V_i)}{\sum_{i=1}^n V_i} \quad (Eq. 4)$$

where:

$\%V_{LO}$ = overall performance of total valves in the applicable process or group of processes

$\%V_{Li}$ = percent leaking valves in subgroup i, most recent value calculated according to the procedures in paragraphs (e)(6)(ii) and (iii) of this section

V_i = number of valves in subgroup i

(iv) *Records.* In addition to records required by paragraph (g) of this section, the owner or operator shall maintain records specified in paragraphs (e)(5)(iv)(A) through (D) of this section.

(A) Which valves are assigned to each subgroup,

(B) Monitoring results and calculations made for each subgroup for each monitoring period,

(C) Which valves are reassigned and when they were reassigned, and

(D) The results of the semiannual overall performance calculation required in paragraph (e)(5)(iii) of this section.

(v) The owner or operator shall notify the Administrator no later than 30 days prior to the beginning of the next monitoring period of the decision to subgroup valves. The notification shall identify the participating processes and the valves assigned to each subgroup.

(vi) *Semiannual reports.* In addition to the information required by paragraph (h)(3) of this section, the owner or operator shall submit in the periodic reports the information specified in paragraphs (e)(5)(vi)(A) and (B) of this section.

(A) Valve reassignments occurring during the reporting period, and

(B) Results of the semiannual overall performance calculation required by paragraph (e)(5)(iii) of this section.

(vii) To determine the monitoring frequency for each subgroup, the calculation procedures of paragraph (e)(6)(iii) of this section shall be used.

(viii) Except for the overall performance calculations required by paragraphs (e)(5)(i) and (e)(5)(iii) of this section, each subgroup shall be treated as if it were a process for the purposes of applying the provisions of this section.

(6)(i) The owner or operator shall decide no later than the implementation date of this subpart or upon revision of an operating permit how to group the processes. Once the owner or operator has decided, all subsequent percentage calculations shall be made on the same basis.

(ii) Percent leaking valves for each group of processes or subgroup shall be determined by the following Equation 5:

$$\%V_L = [V_L/V_T] \times 100 \quad (\text{Eq. 5})$$

Where:

$\%V_L$ = percent leaking valves as determined through periodic monitoring required in paragraphs (e)(2) through (4) of this section.

V_T = total valves monitored, in a monitoring period excluding valves monitored as required by (e)(7)(iii) of this section

(iii) When determining monitoring frequency for each group of processes or subgroup subject to monthly, quarterly, or semiannual monitoring frequencies, the percent leaking valves shall be the arithmetic average of the percent leaking valves from the last two monitoring periods. When determining monitoring frequency for each group of processes or subgroup subject to annual or biennial (once every 2 years) monitoring frequencies, the percent leaking valves shall be the arithmetic average of the percent leaking valves from the last three monitoring periods.

(iv)(A) Nonrepairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and nonrepairable and as required to comply with paragraph (e)(6)(iv)(B) of this section. Otherwise, a number of nonrepairable valves (identified and included in the percent leaking calculation in a previous period) up to a maximum of 1 percent of the total number of valves in organic HAP service at a process may be excluded from calculation of percent leaking valves for subsequent monitoring periods.

(B) If the number of nonrepairable valves exceeds 1 percent of the total number of valves in organic HAP service at a process, the number of nonrepairable valves exceeding 1 percent of the total number of valves in organic HAP service shall be included in the calculation of percent leaking valves.

(7) *Repair provisions.* (i) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in paragraph (b)(4)(i) of this section.

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

(iii) When a leak is repaired, the valve shall be monitored at least once within the first 3 months after its repair. Days that the valve is not in organic HAP service shall not be considered part of this 3 month period. The monitoring required by this paragraph is in addition to the monitoring required to satisfy the definitions of “repaired” and “first attempt at repair.”

(A) The monitoring shall be conducted as specified in §63.180(b) and (c) as appropriate to determine whether the valve has resumed leaking.

(B) Periodic monitoring required by paragraphs (e)(2) through (4) of this section may be used to satisfy the requirements of paragraph (e)(7)(iii) of this section, if the timing of the monitoring period coincides with the time specified in paragraph (e)(7)(iii) of this section. Alternatively, other monitoring may be performed to satisfy the requirements of paragraph (e)(7)(iii) of this section, regardless of whether the timing of the monitoring period for periodic monitoring coincides with the time specified in paragraph (e)(7)(iii) of this section.

(C) If a leak is detected by monitoring that is conducted pursuant to paragraph (e)(7)(iii) of this section, the owner or operator shall follow the provisions of paragraphs (e)(7)(iii)(C)(1) and (2) of this section to determine whether that valve must be counted as a leaking valve for purposes of paragraph (e)(6) of this section.

(1) If the owner or operator elects to use periodic monitoring required by paragraphs (e)(2) through (4) of this section to satisfy the requirements of paragraph (e)(7)(iii) of this section, then the valve shall be counted as a leaking valve.

(2) If the owner or operator elects to use other monitoring prior to the periodic monitoring required by paragraphs (e)(2) through (4) of this section to satisfy the requirements of paragraph (e)(7)(iii) of this section, then the valve shall be counted as a leaking valve unless it is repaired and shown by periodic monitoring not to be leaking.

(8) First attempts at repair include, but are not limited to, the following practices where practicable:

(i) Tightening of bonnet bolts,

- (ii) Replacement of bonnet bolts,
- (iii) Tightening of packing gland nuts, and
- (iv) Injection of lubricant into lubricated packing.

(9) Any equipment located at a plant site with fewer than 250 valves in organic HAP service in the affected source is exempt from the requirements for monthly monitoring specified in paragraph (e)(4)(i) of this section. Instead, the owner or operator shall monitor each valve in organic HAP service for leaks once each quarter, or comply with paragraph (e)(4)(iii), (iv), or (v) of this section, except as provided in paragraph (f) of this section.

(f) *Unsafe to monitor/inspect, difficult to monitor/inspect, and inaccessible equipment.* (1) Equipment that is designated as unsafe to monitor, unsafe to inspect, difficult to monitor, difficult to inspect, or inaccessible is exempt from the monitoring requirements as specified in paragraphs (f)(1)(i) through (iv) of this section provided the owner or operator meets the requirements specified in paragraph (f)(2), (3), or (4) of this section, as applicable. All equipment must be assigned to a group of processes. Ceramic or ceramic-lined connectors are subject to the same requirements as inaccessible connectors.

(i) For pumps and agitators, paragraphs (c)(2), (3), and (4) of this section do not apply.

(ii) For valves, paragraphs (e)(2) through (7) of this section do not apply.

(iii) For connectors, §63.174(b) through (e) and paragraphs (b)(4)(iii)(B) through (F) of this section do not apply.

(iv) For closed-vent systems, §63.172(f)(1) and (2) and §63.172(g) do not apply.

(2) *Equipment that is unsafe to monitor or unsafe to inspect.* (i) Valves, connectors, agitators, and pumps may be designated as unsafe to monitor if the owner or operator determines that monitoring personnel would be exposed to an immediate danger as a consequence of complying with the monitoring requirements referred to in paragraphs (f)(1)(i) through (iii) of this section.

(ii) Any part of a closed-vent system may be designated as unsafe to inspect if the owner or operator determines that monitoring personnel would be exposed to an immediate danger as a consequence of complying with the monitoring requirements referred to in paragraph (f)(1)(iv) of this section.

(iii) The owner or operator of equipment that is designated as unsafe to monitor must have a written plan that requires monitoring of the equipment as frequently as practicable during safe to monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable to the group of processes in which the equipment is located.

(iv) For any parts of a closed-vent system designated as unsafe to inspect, the owner or operator must have a written plan that requires inspection of the closed-vent systems as frequently as practicable during safe to inspect times, but not more frequently than annually.

(3) *Equipment that is difficult to monitor or difficult to inspect.* (i) A valve, agitator, or pump may be designated as difficult to monitor if the owner or operator determines that the valve, agitator, or pump cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface, or it is not accessible in a safe manner when it is in organic HAP service.

(ii) Any part of a closed-vent system may be designated as difficult to inspect if the owner or operator determines that the equipment cannot be inspected without elevating the monitoring personnel more than 2 meters above a support surface, or it is not accessible in a safe manner when it is in organic HAP service.

(iii) At an existing source, any valve, agitator or pump within a group of processes that meets the criteria of paragraph (f)(3)(i) of this section may be designated as difficult to monitor, and any parts of a closed-vent system that meet the requirements of paragraph (f)(3)(ii) of this section may be designated as difficult to inspect. At a new affected source, an owner or operator may designate no more than 3 percent of valves as difficult to monitor.

(iv) The owner or operator of valves, agitators, or pumps designated as difficult to monitor must have a written plan that requires monitoring of the equipment at least once per calendar year or on the periodic monitoring schedule otherwise applicable to the group of processes in which the equipment is located, whichever is less frequent. For any part of a closed-vent system designated as difficult to inspect, the owner or operator must have a written plan that requires inspection of the closed-vent system at least once every 5 years.

(4) *Inaccessible, ceramic, or ceramic-lined connectors.* (i) A connector may be designated as inaccessible if it is:

(A) Buried;

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

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

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

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

(ii) A connector may be designated as inaccessible if it would require elevating the monitoring personnel more than 2 meters above a permanent support surface or would require the erection of scaffold.

(iii) At an existing source, any connector that meets the criteria of paragraph (f)(4)(i) or (ii) of this section may be designated as inaccessible. At a new affected source, an owner or operator may designate no more than 3 percent of connectors as inaccessible.

(iv) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the leak shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in paragraph (b)(4)(i) of this section.

(v) Any connector that is inaccessible or that is ceramic or ceramic-lined is exempt from the recordkeeping and reporting requirements of paragraphs (g) and (h) of this section.

(g) *Recordkeeping requirements.* (1) An owner or operator of more than one group of processes subject to the provisions of this section may comply with the recordkeeping requirements for the groups of processes in one recordkeeping system if the system identifies with each record the program being implemented (e.g., quarterly monitoring) for each type of equipment. All records and information required by this section shall be maintained in a manner that can be readily accessed at the plant site. This could include physically locating the records at the plant site or accessing the records from a central location by computer at the plant site.

(2) *General recordkeeping.* Except as provided in paragraph (g)(5)(i) of this section and in paragraph (a)(9) of this section, the following information pertaining to all equipment subject to the requirements in this section shall be recorded:

(i)(A) A list of identification numbers for equipment (except connectors that are subject to paragraph (f)(4) of this section) subject to the requirements of this section. Except for equipment subject to the recordkeeping requirements in paragraphs (g)(2)(ii) through (viii) of this section, equipment need not be individually identified if, for a particular type of equipment, all items of that equipment in a designated area or length of pipe subject to the provisions of this section are identified as a group, and the number of subject items of equipment is indicated. The list for each type of equipment shall be completed no later than the completion of the initial survey required for that component. The list of identification numbers shall be updated, if needed, to incorporate equipment changes identified during the course of each monitoring period within 90 calendar days, or by the next Periodic Report, following the end of the monitoring period for the type of equipment component monitored, whichever is later.

(B) A schedule for monitoring connectors subject to the provisions of §63.174(a) and valves subject to the provisions of paragraph (e)(4) of this section.

(C) Physical tagging of the equipment to indicate that it is in organic HAP service is not required. Equipment subject to the provisions of this section may be identified on a plant site plan, in log entries, or by other appropriate methods.

(ii)(A) A list of identification numbers for equipment that the owner or operator elects to equip with a closed-vent system and control device, under the provisions of paragraph (c)(7) of this section, §63.164(h), or §63.165(c).

(B) A list of identification numbers for compressors that the owner or operator elects to designate as operating with an instrument reading of less than 500 parts per million above background, under the provisions of §63.164(i).

(iii)(A) A list of identification numbers for pressure relief devices subject to the provisions in §63.165(a).

(B) A list of identification numbers for pressure relief devices equipped with rupture disks, under the provisions of §63.165(d).

(iv) Identification of instrumentation systems subject to the provisions of this section. Individual components in an instrumentation system need not be identified.

(v) The following information shall be recorded for each dual mechanical seal system:

(A) Design criteria required by paragraph (c)(5)(vi)(A) of this section and §63.164(e)(2), and an explanation of the design criteria; and

(B) Any changes to these criteria and the reasons for the changes.

(vi) A list of equipment designated as unsafe to monitor/inspect or difficult to monitor/inspect under paragraph (f) of this section and a copy of the plan for monitoring or inspecting this equipment.

(vii) A list of connectors removed from and added to the process, as described in §63.174(i)(1), and documentation of the integrity of the weld for any removed connectors, as required in §63.174(j). This is not required unless the net credits for removed connectors is expected to be used.

(viii) For equipment that the owner or operator elects to monitor as provided under §63.178(c), a list of equipment added to batch product processes since the last monitoring period required in §63.178(c)(3)(ii) and (iii). This list must be completed for each type of equipment within 90 calendar days, or by the next Periodic Report, following the end of the monitoring period for the type of equipment monitored, whichever is later. Also, if the owner or operator elects to adjust monitoring frequency by the time in use, as provided in §63.178(c)(3)(iii), records demonstrating the proportion of the time during the calendar year the equipment is in use in a manner subject to the provisions of this section are required. Examples of suitable documentation are records of time in use for individual pieces of equipment or average time in use for the process unit.

(3) *Records of visual inspections.* For visual inspections of equipment subject to the provisions of paragraphs (c)(2)(iii) and (c)(5)(iv) of this section, the owner or operator shall document that the inspection was conducted and the date of the inspection. The owner or operator shall

maintain records as specified in paragraph (g)(4) of this section for leaking equipment identified in this inspection, except as provided in paragraph (g)(5) of this section. These records shall be retained for 2 years.

(4) *Monitoring records.* When each leak is detected as specified in paragraph (c) of this section and §63.164, paragraph (e) of this section and §63.169, and §§63.172 and 63.174, the following information shall be recorded and kept for 5 years (at least 2 years onsite, with the remaining 3 years either onsite or offsite):

(i) The instrument and the equipment identification number and the operator name, initials, or identification number.

(ii) The date the leak was detected and the date of the first attempt to repair the leak.

(iii) The date of successful repair of the leak.

(iv) The maximum instrument reading measured by Method 21 of 40 CFR part 60, appendix A, after the leak is successfully repaired or determined to be nonrepairable.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(A) The owner or operator may develop a written procedure that identifies the conditions that justify a delay of repair. The written procedures shall be included in a document that is maintained at the plant site. Reasons for delay of repair may be documented by citing the relevant sections of the written procedure.

(B) If delay of repair was caused by depletion of stocked parts, there must be documentation that the spare parts were sufficiently stocked onsite before depletion and the reason for depletion.

(vi) If repairs were delayed, dates of process shutdowns that occur while the equipment is unrepaired.

(vii)(A) If the alternative in §63.174(c)(1)(ii) is not in use for the monitoring period, identification, either by list, location (area or grouping), or tagging of connectors disturbed since the last monitoring period required in §63.174(b), as described in §63.174(c)(1).

(B) The date and results of follow-up monitoring as required in §63.174(c)(1)(i) and (c)(2)(ii). If identification of disturbed connectors is made by location, then all connectors within the designated location shall be monitored.

(viii) The date and results of the monitoring required in §63.178(c)(3)(i) for equipment added to a batch process since the last monitoring period required in §63.178(c)(3)(ii) and (iii). If no leaking equipment is found in this monitoring, the owner or operator shall record that the inspection was performed. Records of the actual monitoring results are not required.

(ix) Copies of the periodic reports as specified in paragraph (h)(3) of this section, if records are not maintained on a computerized data base capable of generating summary reports from the records.

(5) *Records of pressure tests.* The owner or operator who elects to pressure test a process equipment train or supply lines between storage and processing areas to demonstrate compliance with this section is exempt from the requirements of paragraphs (g)(2), (3), (4), and (6) of this section. Instead, the owner or operator shall maintain records of the following information:

(i) The identification of each product, or product code, produced during the calendar year. It is not necessary to identify individual items of equipment in the process equipment train.

(ii) Physical tagging of the equipment to identify that it is in organic HAP service and subject to the provisions of this section is not required. Equipment in a process subject to the provisions of this section may be identified on a plant site plan, in log entries, or by other appropriate methods.

(iii) The dates of each pressure test required in §63.178(b), the test pressure, and the pressure drop observed during the test.

(iv) Records of any visible, audible, or olfactory evidence of fluid loss.

(v) When a process equipment train does not pass two consecutive pressure tests, the following information shall be recorded in a log and kept for 2 years:

(A) The date of each pressure test and the date of each leak repair attempt.

(B) Repair methods applied in each attempt to repair the leak.

(C) The reason for the delay of repair.

(D) The expected date for delivery of the replacement equipment and the actual date of delivery of the replacement equipment.

(E) The date of successful repair.

(6) *Records of compressor and relief device compliance tests.* The dates and results of each compliance test required for compressors subject to the provisions in §63.164(i) and the dates and results of the monitoring following a pressure release for each pressure relief device subject to the provisions in §§63.165(a) and (b). The results shall include:

(i) The background level measured during each compliance test.

(ii) The maximum instrument reading measured at each piece of equipment during each compliance test.

(7) *Records for closed-vent systems.* The owner or operator shall maintain records of the information specified in paragraphs (g)(7)(i) through (iii) of this section for closed-vent systems and control devices subject to the provisions of paragraph (b)(4)(ii) of this section. The records specified in paragraph (g)(7)(i) of this section shall be retained for the life of the equipment. The records specified in paragraphs (g)(7)(ii) and (g)(7)(iii) of this section shall be retained for 2 years.

(i) The design specifications and performance demonstrations specified in paragraphs (g)(7)(i)(A) through (g)(7)(i)(D) of this section.

(A) Detailed schematics, design specifications of the control device, and piping and instrumentation diagrams.

(B) The dates and descriptions of any changes in the design specifications.

(C) The flare design (i.e., steam assisted, air assisted, or nonassisted) and the results of the compliance demonstration required by §63.11(b).

(D) A description of the parameter or parameters monitored, as required in paragraph (b)(4)(ii) of this section, to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(ii) Records of operation of closed-vent systems and control devices.

(A) Dates and durations when the closed-vent systems and control devices required in paragraph (c) of this section and §§63.164 through 63.166 are not operated as designed as indicated by the monitored parameters, including periods when a flare pilot light system does not have a flame.

(B) Dates and durations during which the monitoring system or monitoring device is inoperative.

(C) Dates and durations of startups and shutdowns of control devices required in paragraph (c)(7) of this section and §§63.164 through 63.166.

(iii) Records of inspections of closed-vent systems subject to the provisions of §63.172.

(A) For each inspection conducted in accordance with the provisions of §63.172(f)(1) or (f)(2) during which no leaks were detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(B) For each inspection conducted in accordance with the provisions of §63.172(f)(1) or (f)(2) during which leaks were detected, the information specified in paragraph (g)(4) of this section shall be recorded.

(8) *Records for components in heavy liquid service.* Information, data, and analysis used to determine that a piece of equipment or process is in heavy liquid service shall be recorded. Such

a determination shall include an analysis or demonstration that the process fluids do not meet the criteria of “in light liquid or gas service.” Examples of information that could document this include, but are not limited to, records of chemicals purchased for the process, analyses of process stream composition, engineering calculations, or process knowledge.

(9) *Records of exempt components.* Identification, either by list, location (area or group) of equipment in organic HAP service less than 300 hours per year subject to the provisions of this section.

(10) *Records of alternative means of compliance determination.* Owners and operators choosing to comply with the requirements of §63.179 shall maintain the following records:

(i) Identification of the process(es) and the organic HAP they handle.

(ii) A schematic of the process, enclosure, and closed-vent system.

(iii) A description of the system used to create a negative pressure in the enclosure to ensure that all emissions are routed to the control device.

(h) *Reporting requirements.* (1) Each owner or operator of a source subject to this section shall submit the reports listed in paragraphs (h)(1)(i) through (ii) of this section.

(i) A Notification of Compliance Status Report described in paragraph (h)(2) of this section,

(ii) Periodic reports described in paragraph (h)(3) of this section.

(2) *Notification of compliance status report.* Each owner or operator of a source subject to this section shall submit the information specified in paragraphs (h)(2)(i) through (iii) of this section in the Notification of Compliance Status Report described in §63.1260(f).

(i) The notification shall provide the information listed in paragraphs (h)(2)(i)(A) through (C) of this section for each process subject to the requirements of paragraphs (b) through (g) of this section.

(A) Process group identification.

(B) Number of each equipment type (e.g., valves, pumps) in organic HAP service, excluding equipment in vacuum service.

(C) Method of compliance with the standard (for example, “monthly leak detection and repair” or “equipped with dual mechanical seals”).

(ii) The notification shall provide the information listed in paragraphs (h)(2)(ii)(A) and (B) of this section for each process subject to the requirements of paragraph (b)(4)(iv) of this section and §63.178(b).

(A) Products or product codes subject to the provisions of this section, and

(B) Planned schedule for pressure testing when equipment is configured for production of products subject to the provisions of this section.

(iii) The notification shall provide the information listed in paragraphs (h)(2)(iii)(A) and (B) of this section for each process subject to the requirements in §63.179.

(A) Process identification.

(B) A description of the system used to create a negative pressure in the enclosure and the control device used to comply with the requirements of paragraph (b)(4)(ii) of this section.

(iv) Section 63.9(j) shall not apply to the Notification of Compliance Status report described in this paragraph (h)(2).

(3) *Periodic reports.* The owner or operator of a source subject to this section shall submit Periodic Reports.

(i) A report containing the information in paragraphs (h)(3)(ii), (iii), and (iv) of this section shall be submitted semiannually. The first report shall be submitted no later than 240 days after the Notification of Compliance Status Report is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status Report is due. Each subsequent report shall cover the 6-month period following the preceding period.

(ii) For equipment complying with the provisions of paragraphs (b) through (g) of this section, except paragraph (b)(4)(iv) of this section and §63.179, the summary information listed in paragraphs (h)(3)(ii)(A) through (L) of this section for each monitoring period during the 6-month period.

(A) The number of valves for which leaks were detected as described in paragraph (e)(3) of this section, the percent leakers, and the total number of valves monitored;

(B) The number of valves for which leaks were not repaired as required in paragraph (e)(7) of this section, identifying the number of those that are determined nonrepairable;

(C) Separately, the number of pumps and agitators for which leaks were detected as described in paragraph (c)(2) of this section, the total number of pumps and agitators monitored, and, for pumps, the percent leakers;

(D) Separately, the number of pumps and agitators for which leaks were not repaired as required in paragraph (c)(3) of this section;

(E) The number of compressors for which leaks were detected as described in §63.164(f);

(F) The number of compressors for which leaks were not repaired as required in §63.164(g);

(G) The number of connectors for which leaks were detected as described in §63.174(a), the percent of connectors leaking, and the total number of connectors monitored;

(H) The number of connectors for which leaks were not repaired as required in §63.174(d), identifying the number of those that are determined nonrepairable;

(I) The facts that explain any delay of repairs and, where appropriate, why a process shutdown was technically infeasible.

(J) The results of all monitoring to show compliance with §§63.164(i), 63.165(a), and 63.172(f) conducted within the semiannual reporting period.

(K) If applicable, the initiation of a monthly monitoring program under either paragraph (c)(4)(ii) or paragraph (e)(4)(i) of this section.

(L) If applicable, notification of a change in connector monitoring alternatives as described in §63.174(c)(1).

(iii) For owners or operators electing to meet the requirements of §63.178(b), the report shall include the information listed in paragraphs (h)(3)(iii)(A) through (E) of this paragraph for each process.

(A) Product process equipment train identification;

(B) The number of pressure tests conducted;

(C) The number of pressure tests where the equipment train failed either the retest or two consecutive pressure tests;

(D) The facts that explain any delay of repairs; and

(E) The results of all monitoring to determine compliance with §63.172(f) of subpart H.

(iv) Any revisions to items reported in earlier Notification of Compliance Status report, if the method of compliance has changed since the last report.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52603, Aug. 29, 2000; 66 FR 40132, Aug. 2, 2001; 76 FR 22600, Apr. 21, 2011]

§63.1256 Standards: Wastewater.

(a) *General.* Each owner or operator of any affected source (existing or new) shall comply with the general wastewater requirements in paragraphs (a)(1) through (3) of this section and the maintenance wastewater provisions in paragraph (a)(4) of this section. An owner or operator may transfer wastewater to a treatment operation not owned by the owner or operator in accordance with paragraph (a)(5) of this section.

(1) *Identify wastewater that requires control.* For each POD, the owner or operator shall comply with the requirements in either paragraph (a)(1)(i) or (ii) of this section to determine whether a wastewater stream is an affected wastewater stream that requires control for soluble and/or partially soluble HAP compounds or to designate the wastewater stream as an affected wastewater stream, respectively. The owner or operator may use a combination of the approaches in paragraphs (a)(1)(i) and (ii) of this section for different affected wastewater generated at the source.

(i) *Determine characteristics of a wastewater stream.* At new and existing sources, a wastewater stream is an affected wastewater stream if the annual average concentration and annual load exceed any of the criteria specified in paragraph (a)(1)(i)(A) through (C) of this section. At new sources, a wastewater stream is subject to additional control requirements if the annual average concentration and annual load exceed the criteria specified in paragraphs (a)(1)(i)(D) of this section. The owner or operator shall comply with the provisions of §63.1257(e)(1) to determine the annual average concentrations and annual load of partially soluble and soluble HAP compounds.

(A) The wastewater stream contains partially soluble HAP compounds at an annual average concentration greater than 1,300 ppmw, and the total soluble and partially soluble HAP load in all wastewater from the PMPU exceeds 0.25 Mg/yr.

(B) The wastewater stream contains partially soluble and/or soluble HAP compounds at an annual average concentration greater than 5,200 ppmw, and the total soluble and partially soluble HAP load in all wastewater from the PMPU exceeds 0.25 Mg/yr.

(C) The wastewater stream contains partially soluble and/or soluble HAP at an annual average concentration of greater than 10,000 ppmw, and the total partially soluble and/or soluble HAP load in all wastewater from the affected source is greater than 1 Mg/yr.

(D) The wastewater stream contains soluble HAP compounds at an annual average concentration greater than 110,000 ppmw, and the total soluble and partially soluble HAP load in all wastewater from the PMPU exceeds 1 Mg/yr.

(ii) *Designate wastewater as affected wastewater.* For existing sources, the owner or operator may elect to designate wastewater streams as meeting the criteria of either paragraphs (a)(1)(i)(A), (B), or (C) of this section. For new sources, the owner or operator may elect to designate wastewater streams meeting the criterion in paragraph (a)(1)(i)(D) or for wastewater known to contain no soluble HAP, as meeting the criterion in paragraph (a)(1)(i)(A) of this section. For designated wastewater the procedures specified in paragraphs (a)(1)(ii)(A) and (B) of this section shall be followed, except as specified in paragraphs (g)(8)(i), (g)(9)(i), and (g)(10) of this section. The owner or operator is not required to determine the annual average concentration or load for each designated wastewater stream for the purposes of this section.

(A) From the POD for the wastewater stream that is designated as an affected wastewater stream to the location where the owner or operator elects to designate such wastewater stream as an

affected wastewater stream, the owner or operator shall comply with all applicable emission suppression requirements specified in paragraphs (b) through (f) of this section.

(B) From the location where the owner or operator designates a wastewater stream as an affected wastewater stream, such wastewater stream shall be managed in accordance with all applicable emission suppression requirements specified in paragraphs (b) through (f) of this section and with the treatment requirements in paragraph (g) of this section.

(iii) *Scrubber effluent.* Effluent from a water scrubber that has been used to control Table 2 HAP-containing vent streams that are controlled in order to meet the process vent requirements in §63.1254 of this subpart is considered an affected wastewater stream.

(2) *Requirements for affected wastewater.* (i) An owner or operator of a facility shall comply with the applicable requirements for wastewater tanks, surface impoundments, containers, individual drain systems, and oil/water separators as specified in paragraphs (b) through (f) of this section, except as provided in paragraph (g)(3) of this section.

(ii) Comply with the applicable requirements for control of soluble and partially soluble compounds as specified in paragraph (g) of this section. Alternatively, the owner or operator may elect to comply with the treatment provisions specified in paragraph (a)(5) of this section.

(iii) Comply with the applicable monitoring and inspection requirements specified in §63.1258.

(iv) Comply with the applicable recordkeeping and reporting requirements specified in §§63.1259 and 63.1260.

(3) *Requirements for multiphase discharges.* The owner or operator shall not discharge a separate phase that can be isolated through gravity separation from the aqueous phase to a waste management or treatment unit, unless the stream is discharged to a treatment unit in compliance with paragraph (g)(13) of this section.

(4) *Maintenance wastewater requirements.* Each owner or operator of a source subject to this subpart shall comply with the requirements of paragraphs (a)(4)(i) through (iv) of this section for maintenance wastewater containing partially soluble or soluble HAP listed in Tables 2 and 3 of this subpart. Maintenance wastewater is exempt from all other provisions of this subpart.

(i) The owner or operator shall prepare a description of maintenance procedures for management of wastewater generated from the emptying and purging of equipment in the process during temporary shutdowns for inspections, maintenance, and repair (*i.e.*, a maintenance turnaround) and during periods which are not shutdowns (*i.e.*, routine maintenance). The descriptions shall be included in a document that is maintained at the plant site and shall:

(A) Specify the process equipment or maintenance tasks that are anticipated to create wastewater during maintenance activities; and

(B) Specify the procedures that will be followed to properly manage the wastewater and minimize organic HAP emissions to the atmosphere; and

(C) Specify the procedures to be followed when clearing materials from process equipment.

(ii) The owner or operator shall modify and update the information required by paragraph (a)(4)(i) of this section as needed following each maintenance procedure based on the actions taken and the wastewater generated in the preceding maintenance procedure.

(5) *Offsite treatment or onsite treatment not owned or operated by the source.* The owner or operator may elect to transfer affected wastewater streams or a residual removed from such affected wastewater to an onsite treatment operation not owned or operated by the owner or operator of the source generating the wastewater or residual, or to an offsite treatment operation.

(i) The owner or operator transferring the wastewater or residual shall:

(A) Comply with the provisions specified in paragraphs (b) through (f) of this section for each waste management unit that receives or manages affected wastewater or a residual removed from affected wastewater prior to shipment or transport.

(B) Include a notice with each shipment or transport of affected wastewater or residual removed from affected wastewater. The notice shall state that the affected wastewater or residual contains organic HAP that are to be treated in accordance with the provisions of this subpart. When the transport is continuous or ongoing (for example, discharge to a publicly-owned treatment works), the notice shall be submitted to the treatment operator initially and whenever there is a change in the required treatment. The owner or operator shall keep a record of the notice in accordance with §63.1259(g).

(ii) The owner or operator may not transfer the affected wastewater or residual unless the transferee has submitted to the EPA a written certification that the transferee will manage and treat any affected wastewater or residual removed from affected wastewater received from a source subject to the requirements of this subpart in accordance with the requirements of either:

(A) Paragraphs (b) through (i) of this section; or

(B) Subpart D of this part if alternative emission limitations have been granted the transferor in accordance with those provisions; or

(C) Section 63.6(g); or

(D) If the affected wastewater streams or residuals removed from affected wastewater streams received by the transferee contain less than 50 ppmw of partially soluble HAP, then the transferee must, at a minimum, manage and treat the affected wastewater streams and residuals in accordance with one of the following:

(1) Comply with paragraph (g)(10) of this section and cover the waste management units up to the activated sludge unit; or

(2) Comply with paragraphs (g)(11)(i), (ii), and (h) of this section and cover the waste management units up to the activated sludge unit; or

(3) Comply with paragraph (g)(10) of this section provided that the owner or operator of the affected source demonstrates that less than 5 percent of the total soluble HAP is emitted from waste management units up to the activated sludge unit; or

(4) Comply with paragraphs (g)(11)(i), (ii), and (h) of this section provided that the owner or operator of the affected source demonstrates that less than 5 percent of the total soluble HAP is emitted from waste management units up to the activated sludge unit.

(iii) The certifying entity may revoke the written certification by sending a written statement to the EPA and the owner or operator giving at least 90 days notice that the certifying entity is rescinding acceptance of responsibility for compliance with the regulatory provisions listed in this paragraph. Upon expiration of the notice period, the owner or operator may not transfer the wastewater stream or residual to the treatment operation.

(iv) By providing this written certification to the EPA, the certifying entity accepts responsibility for compliance with the regulatory provisions listed in paragraph (a)(5)(ii) of this section with respect to any shipment of wastewater or residual covered by the written certification. Failure to abide by any of those provisions with respect to such shipments may result in enforcement action by the EPA against the certifying entity in accordance with the enforcement provisions applicable to violations of these provisions by owners or operators of sources.

(v) Written certifications and revocation statements, to the EPA from the transferees of wastewater or residuals shall be signed by the responsible official of the certifying entity, provide the name and address of the certifying entity, and be sent to the appropriate EPA Regional Office at the addresses listed in §63.13. Such written certifications are not transferable by the treater.

(b) *Wastewater tanks.* For each wastewater tank that receives, manages, or treats affected wastewater or a residual removed from affected wastewater, the owner or operator shall comply with the requirements of either paragraph (b)(1) or (2) of this section as specified in Table 6 of this subpart.

(1) The owner or operator shall operate and maintain a fixed roof except when the contents of the wastewater tank are heated, treated by means of an exothermic reaction, or sparged, during which time the owner or operator shall comply with the requirements specified in paragraph (b)(2) of this section. For the purposes of this paragraph, the requirements of paragraph (b)(2) of this section are satisfied by operating and maintaining a fixed roof if the owner or operator demonstrates that the total soluble and partially soluble HAP emissions from the wastewater tank are no more than 5 percent higher than the emissions would be if the contents of the wastewater tank were not heated, treated by an exothermic reaction, or sparged.

(2) The owner or operator shall comply with the requirements in paragraphs (b)(3) through (9) of this section and shall operate and maintain one of the emission control techniques listed in paragraphs (b)(2)(i) through (iii) of this section.

(i) A fixed roof and a closed-vent system that routes the organic HAP vapors vented from the wastewater tank to a control device; or

(ii) A fixed roof and an internal floating roof that meets the requirements specified in §63.119(b), with the differences noted in §63.1257(c)(3)(i) through (iii) for the purposes of this subpart; or

(iii) An external floating roof that meets the requirements specified in §§63.119(c), 63.120(b)(5), and 63.120(b)(6), with the differences noted in §63.1257(c)(3)(i) through (v) for the purposes of this subpart.

(3) If the owner or operator elects to comply with the requirements of paragraph (b)(2)(i) of this section, the fixed roof shall meet the requirements of paragraph (b)(3)(i) of this section, the control device shall meet the requirements of paragraph (b)(3)(ii) of this section, and the closed-vent system shall meet the requirements of paragraph (b)(3)(iii) of this section.

(i) The fixed roof shall meet the following requirements:

(A) Except as provided in paragraph (b)(3)(iv) of this section, the fixed roof and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be maintained in accordance with the requirements specified in §63.1258(h).

(B) Each opening shall be maintained in a closed position (e.g., covered by a lid) at all times that the wastewater tank contains affected wastewater or residual removed from affected wastewater except when it is necessary to use the opening for wastewater sampling, removal, or for equipment inspection, maintenance, or repair.

(ii) The control device shall be designed, operated, and inspected in accordance with the requirements of paragraph (h) of this section.

(iii) Except as provided in paragraph (b)(3)(iv) of this section, the closed-vent system shall be inspected in accordance with the requirements of §63.1258(h).

(iv) For any fixed roof tank and closed-vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in §63.1258(h).

(4) If the owner or operator elects to comply with the requirements of paragraph (b)(2)(ii) of this section, the floating roof shall be inspected according to the procedures specified in §63.120(a)(2) and (3), with the differences noted in §63.1257(c)(3)(iv) for the purposes of this subpart.

(5) Except as provided in paragraph (b)(6) of this section, if the owner or operator elects to comply with the requirements of paragraph (b)(2)(iii) of this section, seal gaps shall be measured according to the procedures specified in §63.120(b)(2)(i) through (b)(4) and the wastewater tank shall be inspected to determine compliance with §63.120(b)(5) and (6) according to the schedule specified in §63.120(b)(1)(i) through (iii).

(6) If the owner or operator determines that it is unsafe to perform the seal gap measurements specified in §63.120(b)(2)(i) through (b)(4) or to inspect the wastewater tank to determine compliance with §63.120(b)(5) and (6) because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the owner or operator shall comply with the requirements in either paragraph (b)(6)(i) or (ii) of this section.

(i) The owner or operator shall measure the seal gaps or inspect the wastewater tank within 30 calendar days of the determination that the floating roof is unsafe.

(ii) The owner or operator shall empty and remove the wastewater tank from service within 45 calendar days of determining that the roof is unsafe. If the wastewater tank cannot be emptied within 45 calendar days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. Documentation of a decision to utilize an extension shall include an explanation of why it was unsafe to perform the inspection or seal gap measurement, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the wastewater tank will be emptied as soon as possible.

(7) Except as provided in paragraph (b)(6) of this section, each wastewater tank shall be inspected initially, and semiannually thereafter, for improper work practices in accordance with §63.1258(g). For wastewater tanks, improper work practice includes, but is not limited to, leaving open any access door or other opening when such door or opening is not in use.

(8) Except as provided in paragraph (b)(6) of this section, each wastewater tank shall be inspected for control equipment failures as defined in paragraph (b)(8)(i) of this section according to the schedule in paragraphs (b)(8)(ii) and (iii) of this section in accordance with §63.1258(g).

(i) Control equipment failures for wastewater tanks include, but are not limited to, the conditions specified in paragraphs (b)(8)(i)(A) through (I) of this section.

(A) The floating roof is not resting on either the surface of the liquid or on the leg supports.

(B) There is stored liquid on the floating roof.

(C) A rim seal is detached from the floating roof.

(D) There are holes, tears, cracks or gaps in the rim seal or seal fabric of the floating roof.

(E) There are visible gaps between the seal of an internal floating roof and the wall of the wastewater tank.

(F) There are gaps between the metallic shoe seal or the liquid mounted primary seal of an external floating roof and the wall of the wastewater tank that exceed 212 square centimeters per meter of tank diameter or the width of any portion of any gap between the primary seal and the tank wall exceeds 3.81 centimeters.

(G) There are gaps between the secondary seal of an external floating roof and the wall of the wastewater tank that exceed 21.2 square centimeters per meter of tank diameter or the width of any portion of any gap between the secondary seal and the tank wall exceeds 1.27 centimeters.

(H) Where a metallic shoe seal is used on an external floating roof, one end of the metallic shoe does not extend into the stored liquid or one end of the metallic shoe does not extend a minimum vertical distance of 61 centimeters above the surface of the stored liquid.

(I) A gasket, joint, lid, cover, or door has a crack or gap, or is broken.

(ii) The owner or operator shall inspect for the control equipment failures in paragraphs (b)(8)(i)(A) through (H) according to the schedule specified in paragraphs (b)(4) and (5) of this section.

(iii) The owner or operator shall inspect for the control equipment failures in paragraph (b)(8)(i)(I) of this section initially, and semiannually thereafter.

(9) Except as provided in paragraph (i) of this section, when an improper work practice or a control equipment failure is identified, first efforts at repair shall be made no later than 5 calendar days after identification and repair shall be completed within 45 calendar days after identification. If a failure that is detected during inspections required by this section cannot be repaired within 45 calendar days and if the tank cannot be emptied within 45 calendar days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the tank will be emptied as soon as practical.

(10) The emission limits specified in §63.1256 (b)(2) and (h) for control devices used to control emissions from wastewater tanks do not apply during periods of planned routine maintenance of the control device(s) of no more than 240 hours in any 365-day period. The owner or operator may submit an application to the Administrator requesting an extension of this time limit to a total of 360 hours in any 365-day period. The application must explain why the extension is needed, it must specify that no affected wastewater will be added to the tank between the time the 240-hour limit is exceeded and the control device is again operational, and it must be submitted at least 60 days before the 240-hour limit will be exceeded. Wastewater tanks shall not be sparged with air or other gases without an operational control device.

(c) *Surface impoundments.* For each surface impoundment that receives, manages, or treats affected wastewater or a residual removed from affected wastewater, the owner or operator shall comply with the requirements of paragraphs (c)(1), (2), and (3) of this section.

(1) The owner or operator shall operate and maintain on each surface impoundment either a cover (e.g., air-supported structure or rigid cover) and a closed-vent system that routes the organic hazardous air pollutants vapors vented from the surface impoundment to a control device in accordance with paragraphs (c)(1)(i), (iii), (iv), and (v) of this section, or a floating flexible membrane cover as specified in paragraph (c)(1)(ii) of this section.

(i) The cover and all openings shall meet the following requirements:

(A) Except as provided in paragraph (c)(1)(v) of this section, the cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be maintained in accordance with the requirements specified in §63.1258(h).

(B) Each opening shall be maintained in a closed position (e.g., covered by a lid) at all times that affected wastewater or residual removed from affected wastewater is in the surface impoundment except when it is necessary to use the opening for sampling, removal, or for equipment inspection, maintenance, or repair.

(C) The cover shall be used at all times that affected wastewater or residual removed from affected wastewater is in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228.

(ii) Floating flexible membrane covers shall meet the requirements specified in paragraphs (c)(1)(ii)(A) through (F) of this section.

(A) The floating flexible cover shall be designed to float on the liquid surface during normal operations, and to form a continuous barrier over the entire surface area of the liquid.

(B) The cover shall be fabricated from a synthetic membrane material that is either:

(1) High density polyethylene (HDPE) with a thickness no less than 2.5 millimeters (100 mils);
or

(2) A material or a composite of different materials determined to have both organic permeability properties that are equivalent to those of the material listed in paragraph (c)(1)(ii)(B)(1) of this section, and chemical and physical properties that maintain the material integrity for the intended service life of the material.

(C) The cover shall be installed in a manner such that there are no visible cracks, holes, gaps, or other open spaces between cover section seams or between the interface of the cover edge and its foundation mountings.

(D) Except as provided for in paragraph (c)(1)(ii)(E) of this section, each opening in the floating membrane cover shall be equipped with a closure device designed to operate such that when the closure device is secured in the closed position there are no visible cracks, holes, gaps, or other

open spaces in the closure device or between the perimeter of the cover opening and the closure device.

(E) The floating membrane cover may be equipped with one or more emergency cover drains for removal of stormwater. Each emergency cover drain shall be equipped with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening or a flexible fabric sleeve seal.

(F) The closure devices shall be made of suitable materials that will minimize exposure of organic HAP to the atmosphere, to the extent practical, and will maintain the integrity of the equipment throughout its intended service life. Factors to be considered in designing the closure devices shall include: the effects of any contact with the liquid and its vapor managed in the surface impoundment; the effects of outdoor exposure to wind, moisture, and sunlight; and the operating practices used for the surface impoundment on which the floating membrane cover is installed.

(G) Whenever affected wastewater or residual from affected wastewater is in the surface impoundment, the floating membrane cover shall float on the liquid and each closure device shall be secured in the closed position. Opening of closure devices or removal of the cover is allowed to provide access to the surface impoundment for performing routine inspection, maintenance, or other activities needed for normal operations and/or to remove accumulated sludge or other residues from the bottom of surface impoundment. Openings shall be maintained in accordance with §63.1258(h).

(iii) The control device shall be designed, operated, and inspected in accordance with paragraph (h) of this section.

(iv) Except as provided in paragraph (c)(1)(v) of this section, the closed-vent system shall be inspected in accordance with §63.1258(h).

(v) For any cover and closed-vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in §63.1258(h).

(2) Each surface impoundment shall be inspected initially, and semiannually thereafter, for improper work practices and control equipment failures in accordance with §63.1258(g).

(i) For surface impoundments, improper work practice includes, but is not limited to, leaving open any access hatch or other opening when such hatch or opening is not in use.

(ii) For surface impoundments, control equipment failure includes, but is not limited to, any time a joint, lid, cover, or door has a crack or gap, or is broken.

(3) Except as provided in paragraph (i) of this section, when an improper work practice or a control equipment failure is identified, first efforts at repair shall be made no later than 5

calendar days after identification and repair shall be completed within 45 calendar days after identification.

(d) *Containers.* For each container that receives, manages, or treats affected wastewater or a residual removed from affected wastewater, the owner or operator shall comply with the requirements of paragraphs (d)(1) through (5) of this section.

(1) The owner or operator shall operate and maintain a cover on each container used to handle, transfer, or store affected wastewater or a residual removed from affected wastewater in accordance with the following requirements:

(i) Except as provided in paragraph (d)(3)(iv) of this section, if the capacity of the container is greater than 0.42 m³, the cover and all openings (e.g., bungs, hatches, sampling points, and pressure relief valves) shall be controlled in accordance with the requirements of either paragraph (d)(1)(i)(A) or (d)(1)(i)(B) of this section.

(A) The requirements specified in §63.1258(h); or

(B) The requirements of subpart PP of this part for containers using level 2 controls that meet the definitions in §63.923(b)(1) or (2).

(ii) If the capacity of the container is less than or equal to 0.42 m³, the owner or operator shall comply with either paragraph (d)(1)(ii)(A) or (B) of this section.

(A) The container must meet existing Department of Transportation specifications and testing requirements under 49 CFR part 178; or

(B) Except as provided in paragraph (d)(3)(iv) of this section, the cover and all openings shall be maintained without leaks as specified in §63.1258(h).

(iii) The cover and all openings shall be maintained in a closed position (e.g., covered by a lid) at all times that affected wastewater or a residual removed from affected wastewater is in the container except when it is necessary to use the opening for filling, removal, inspection, sampling, or pressure relief events related to safety considerations.

(2) *Filling of large containers.* Pumping affected wastewater or a residual removed from affected wastewater into a container with a capacity greater than or equal to 0.42 m³ shall be conducted in accordance with the conditions in paragraphs (d)(2)(i) and (ii) of this section.

(i) Comply with any one of the procedures specified in paragraph (d)(2)(i)(A), (B), or (C) of this section.

(A) Use a submerged fill pipe. The submerged fill pipe outlet shall extend to no more than 6 inches or within two fill pipe diameters of the bottom of the container while the container is being filled.

(B) Locate the container within an enclosure with a closed-vent system that routes the organic HAP vapors vented from the container to a control device.

(C) Use a closed-vent system to vent the displaced organic vapors vented from the container to a control device or back to the equipment from which the wastewater is transferred.

(ii) The cover shall remain in place and all openings shall be maintained in a closed position except for those openings required for the submerged fill pipe and for venting of the container to prevent physical damage or permanent deformation of the container or cover.

(3) During treatment of affected wastewater or a residual removed from affected wastewater, including aeration, thermal or other treatment, in a container, whenever it is necessary for the container to be open, the container shall be located within an enclosure with a closed-vent system that routes the organic HAP vapors vented from the container to a control device.

(i) Except as provided in paragraph (d)(3)(iv) of this section, the enclosure and all openings (e.g., doors, hatches) shall be maintained in accordance with the requirements specified in §63.1258(h).

(ii) The control device shall be designed, operated, and inspected in accordance with paragraph (h) of this section.

(iii) Except as provided in paragraph (d)(3)(iv) of this section, the closed-vent system shall be inspected in accordance with §63.1258(h).

(iv) For any enclosure and closed-vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in §63.1258(h).

(4) Each container shall be inspected initially, and semiannually thereafter, for improper work practices and control equipment failures in accordance with §63.1258(g).

(i) For containers, improper work practice includes, but is not limited to, leaving open any access hatch or other opening when such hatch or opening is not in use.

(ii) For containers, control equipment failure includes, but is not limited to, any time a cover or door has a gap or crack, or is broken.

(5) Except as provided in paragraph (i) of this section, when an improper work practice or a control equipment failure is identified, first efforts at repair shall be made no later than 5 calendar days after identification and repair shall be completed within 15 calendar days after identification.

(e) *Individual drain systems.* For each individual drain system that receives or manages affected wastewater or a residual removed from affected wastewater, the owner or operator shall comply

with the requirements of paragraphs (e) (1), (2), and (3) or with paragraphs (e) (4), (5), and (6) of this section.

(1) If the owner or operator elects to comply with this paragraph, the owner or operator shall operate and maintain on each opening in the individual drain system a cover and if vented, route the vapors to a process or through a closed-vent system to a control device. The owner or operator shall comply with the requirements of paragraphs (e)(1) (i) through (v) of this section.

(i) The cover and all openings shall meet the following requirements:

(A) Except as provided in paragraph (e)(1)(iv) of this section, the cover and all openings (e.g., access hatches, sampling ports) shall be maintained in accordance with the requirements specified in §63.1258(h).

(B) The cover and all openings shall be maintained in a closed position at all times that affected wastewater or a residual removed from affected wastewater is in the drain system except when it is necessary to use the opening for sampling or removal, or for equipment inspection, maintenance, or repair.

(ii) The control device shall be designed, operated, and inspected in accordance with paragraph (h) of this section.

(iii) Except as provided in paragraph (e)(1)(iv) of this section, the closed-vent system shall be inspected in accordance with §63.1258(h).

(iv) For any cover and closed-vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in §63.1258(h).

(v) The individual drain system shall be designed and operated to segregate the vapors within the system from other drain systems and the atmosphere.

(2) Each individual drain system shall be inspected initially, and semiannually thereafter, for improper work practices and control equipment failures, in accordance with §63.1258(g).

(i) For individual drain systems, improper work practice includes, but is not limited to, leaving open any access hatch or other opening when such hatch or opening is not in use for sampling or removal, or for equipment inspection, maintenance, or repair.

(ii) For individual drain systems, control equipment failure includes, but is not limited to, any time a joint, lid, cover, or door has a gap or crack, or is broken.

(3) Except as provided in paragraph (i) of this section, when an improper work practice or a control equipment failure is identified, first efforts at repair shall be made no later than 5 calendar days after identification and repair shall be completed within 15 calendar days after identification.

(4) If the owner or operator elects to comply with this paragraph, the owner or operator shall comply with the requirements in paragraphs (e)(4) (i) through (iii) of this section:

(i) Each drain shall be equipped with water seal controls or a tightly fitting cap or plug. The owner or operator shall comply with paragraphs (e)(4)(i)(A) and (B) of this section.

(A) For each drain equipped with a water seal, the owner or operator shall ensure that the water seal is maintained. For example, a flow-monitoring device indicating positive flow from a main to a branch water line supplying a trap or water being continuously dripped into the trap by a hose could be used to verify flow of water to the trap. Visual observation is also an acceptable alternative.

(B) If a water seal is used on a drain receiving affected wastewater, the owner or operator shall either extend the pipe discharging the wastewater below the liquid surface in the water seal of the receiving drain, or install a flexible shield (or other enclosure which restricts wind motion across the open area between the pipe and the drain) that encloses the space between the pipe discharging the wastewater to the drain receiving the wastewater. (Water seals which are used on hubs receiving wastewater that is not subject to the provisions of this subpart for the purpose of eliminating cross ventilation to drains carrying affected wastewater are not required to have a flexible shield or extended subsurface discharging pipe.)

(ii) Each junction box shall be equipped with a tightly fitting solid cover (i.e., no visible gaps, cracks, or holes) which shall be kept in place at all times except during inspection and maintenance. If the junction box is vented, the owner or operator shall comply with the requirements in paragraph (e)(4)(ii) (A) or (B) of this section.

(A) The junction box shall be vented to a process or through a closed-vent system to a control device. The closed-vent system shall be inspected in accordance with the requirements of §63.1258(h) and the control device shall be designed, operated, and inspected in accordance with the requirements of paragraph (h) of this section.

(B) If the junction box is filled and emptied by gravity flow (i.e., there is no pump) or is operated with no more than slight fluctuations in the liquid level, the owner or operator may vent the junction box to the atmosphere provided that the junction box complies with the requirements in paragraphs (e)(4)(ii)(B) (1) and (2) of this section.

(1) The vent pipe shall be at least 90 centimeters in length and no greater than 10.2 centimeters in nominal inside diameter.

(2) Water seals shall be installed and maintained at the wastewater entrance(s) to or exit from the junction box restricting ventilation in the individual drain system and between components in the individual drain system. The owner or operator shall demonstrate (e.g., by visual inspection or smoke test) upon request by the Administrator that the junction box water seal is properly designed and restricts ventilation.

(iii) The owner or operator shall operate and maintain sewer lines as specified in paragraphs (e)(4)(iii)(A) and (B) of this section.

(A) Except as specified in paragraph (e)(4)(iii)(B) of this section, each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visible gaps or cracks in joints, seals, or other emission interfaces.

NOTE: This provision applies to sewers located inside and outside of buildings.

(B) A sewer line connected to drains that are in compliance with paragraph (e)(4)(i) of this section may be vented to the atmosphere, provided that the sewer line entrance to the first downstream junction box is water sealed and the sewer line vent pipe is designed as specified in paragraph (e)(4)(ii)(B)(I) of this section.

(5) Equipment used to comply with paragraphs (e)(4) (i), (ii), or (iii) of this section shall be inspected as follows:

(i) Each drain using a tightly fitting cap or plug shall be visually inspected initially, and semiannually thereafter, to ensure caps or plugs are in place and that there are no gaps, cracks, or other holes in the cap or plug.

(ii) Each junction box shall be visually inspected initially, and semiannually thereafter, to ensure that there are no gaps, cracks, or other holes in the cover.

(iii) The unburied portion of each sewer line shall be visually inspected initially, and semiannually thereafter, for indication of cracks or gaps that could result in air emissions.

(6) Except as provided in paragraph (i) of this section, when a gap, hole, or crack is identified in a joint or cover, first efforts at repair shall be made no later than 5 calendar days after identification, and repair shall be completed within 15 calendar days after identification.

(f) *Oil-water separators.* For each oil-water separator that receives, manages, or treats affected wastewater or a residual removed from affected wastewater, the owner or operator shall comply with the requirements of paragraphs (f)(1) through (6) of this section.

(1) The owner or operator shall maintain one of the following:

(i) A fixed roof and a closed-vent system that routes the organic HAP vapors vented from the oil-water separator to a control device. The fixed roof, closed-vent system, and control device shall meet the requirements specified in paragraph (f)(2) of this section;

(ii) A floating roof that meets the requirements in 40 CFR 60.693-2(a)(1)(i), (a)(1)(ii), (a)(2), (a)(3), and (a)(4). For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, the owner or operator shall operate and maintain a fixed roof, closed-vent system, and control device that meet the requirements specified in paragraph (f)(2) of this section.

(2) A fixed roof shall meet the requirements of paragraph (f)(2)(i) of this section, a control device shall meet the requirements of paragraph (f)(2)(ii) of this section, and a closed-vent system shall meet the requirements of (f)(2)(iii) of this section.

(i) The fixed roof shall meet the following requirements:

(A) Except as provided in (f)(2)(iv) of this section, the fixed roof and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be maintained in accordance with the requirements specified in §63.1258(h).

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that the oil-water separator contains affected wastewater or a residual removed from affected wastewater except when it is necessary to use the opening for sampling or removal, or for equipment inspection, maintenance, or repair.

(ii) The control device shall be designed, operated, and inspected in accordance with the requirements of paragraph (h) of this section.

(iii) Except as provided in paragraph (f)(2)(iv) of this section, the closed-vent system shall be inspected in accordance with the requirements of §63.1258(h).

(iv) For any fixed-roof and closed-vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements of §63.1258(h).

(3) If the owner or operator elects to comply with the requirements of paragraph (f)(1)(ii) of this section, seal gaps shall be measured according to the procedures specified in 40 CFR part 60, subpart QQQ §60.696(d)(1) and the schedule specified in paragraphs (f)(3)(i) and (ii) of this section.

(i) Measurement of primary seal gaps shall be performed within 60 calendar days after installation of the floating roof and introduction of affected wastewater or a residual removed from affected wastewater and once every 5 years thereafter.

(ii) Measurement of secondary seal gaps shall be performed within 60 calendar days after installation of the floating roof and introduction of affected wastewater or a residual removed from affected wastewater and once every year thereafter.

(4) Each oil-water separator shall be inspected initially, and semiannually thereafter, for improper work practices in accordance with §63.1258(g). For oil-water separators, improper work practice includes, but is not limited to, leaving open or ungasketed any access door or other opening when such door or opening is not in use.

(5) Each oil-water separator shall be inspected for control equipment failures as defined in paragraph (f)(5)(i) of this section according to the schedule specified in paragraphs (f)(5)(ii) and (iii) of this section.

(i) For oil-water separators, control equipment failure includes, but is not limited to, the conditions specified in paragraphs (f)(5)(i)(A) through (G) of this section.

(A) The floating roof is not resting on either the surface of the liquid or on the leg supports.

(B) There is stored liquid on the floating roof.

(C) A rim seal is detached from the floating roof.

(D) There are holes, tears, or other open spaces in the rim seal or seal fabric of the floating roof.

(E) There are gaps between the primary seal and the separator wall that exceed 67 square centimeters per meter of separator wall perimeter or the width of any portion of any gap between the primary seal and the separator wall exceeds 3.8 centimeters.

(F) There are gaps between the secondary seal and the separator wall that exceed 6.7 square centimeters per meter of separator wall perimeter or the width of any portion of any gap between the secondary seal and the separator wall exceeds 1.3 centimeters.

(G) A gasket, joint, lid, cover, or door has a gap or crack, or is broken.

(ii) The owner or operator shall inspect for the control equipment failures in paragraphs (f)(5)(i)(A) through (F) according to the schedule specified in paragraph (f)(3) of this section.

(iii) The owner or operator shall inspect for control equipment failures in paragraph (f)(5)(i)(G) of this section initially, and semiannually thereafter.

(6) Except as provided in paragraph (i) of this section, when an improper work practice or a control equipment failure is identified, first efforts at repair shall be made no later than 5 calendar days after identification and repair shall be completed within 45 calendar days after identification.

(g) *Performance standards for treatment processes managing wastewater and/or residuals removed from wastewater.* This section specifies the performance standards for treating affected wastewater. The owner or operator shall comply with the requirements as specified in paragraphs (g)(1) through (6) of this section. Where multiple compliance options are provided, the options may be used in combination for different wastewater and/or for different compounds (e.g., soluble versus partially soluble compounds) in the same wastewater, except where otherwise provided in this section. Once affected wastewater or a residual removed from affected wastewater has been treated in accordance with this subpart, it is no longer subject to the requirements of this subpart.

(1) *Existing source.* For a wastewater stream at an existing source that exceeds or is designated to exceed the concentration and load criteria in paragraph (a)(1)(i)(A) of this section, the owner or operator shall comply with a control option in paragraph (g)(8) of this section. For a wastewater stream at an existing source that exceeds the concentration and load criteria in either

paragraph (a)(1)(i)(B) or (C) of this section, the owner or operator shall comply with a control option in paragraph (g)(8) of this section and a control option in paragraph (g)(9) of this section. As an alternative to the control options in paragraphs (g)(8) and (g)(9) of this section, the owner or operator may comply with a control option in either paragraph (g)(10), (11) or (13) of this section, as applicable.

(2) *New source.* For a wastewater stream at a new source that exceeds or is designated to exceed the concentration and load criteria in paragraph (a)(1)(i)(A) of this section, the owner or operator shall comply with a control option in paragraph (g)(8) of this section. For wastewater at a new source that exceeds the concentration and load criteria in either paragraph (a)(1)(i)(B) or (C) of this section, but does not exceed the criteria in paragraph (a)(1)(i)(D) of this section, the owner or operator shall comply with a control option in paragraph (g)(8) of this section and a control option in paragraph (g)(9) of this section. As an alternative to the control options in paragraphs (g)(8) and/or (9) of this section, the owner or operator may comply with a control option in either paragraph (g)(10), (11), or (13) of this section, as applicable. For a wastewater stream at a new source that exceeds or is designated to exceed the concentration and load criteria in paragraph (a)(1)(i)(D) of this section, the owner or operator shall comply with a control option in paragraph (g)(12) or (13) of this section.

(3) *Biological treatment processes.* Biological treatment processes in compliance with this section may be either open or closed biological treatment processes as defined in §63.1251. An open biological treatment process in compliance with this section need not be covered and vented to a control device. An open or a closed biological treatment process in compliance with this section and using §63.1257(e)(2)(iii)(E) or (F) to demonstrate compliance is not subject to the requirements of paragraphs (b) and (c) of this section. A closed biological treatment process in compliance with this section and using §63.1257(e)(2)(iii)(G) to demonstrate compliance shall comply with the requirements of paragraphs (b) and (c) of this section. Waste management units upstream of an open or closed biological treatment process shall meet the requirements of paragraphs (b) through (f) of this section, as applicable.

(4) *Performance tests and design evaluations.* If the Resource Conservation and Recovery Act (RCRA) option [paragraph (g)(13) of this section] or the enhanced biological treatment process for soluble HAP compounds option [paragraph (g)(10) of this section] is selected to comply with this section, neither a design evaluation nor a performance test is required. For any other nonbiological treatment process, and for closed biological treatment processes as defined in §63.1251, the owner or operator shall conduct either a design evaluation as specified in §63.1257(e)(2)(ii) or performance test as specified in §63.1257(e)(2)(iii). For each open biological treatment process as defined in §63.1251, the owner or operator shall conduct a performance test as specified in §63.1257(e)(2)(iii)(E) or (F).

(5) *Control device requirements.* When gases are vented from the treatment process, the owner or operator shall comply with the applicable control device requirements specified in paragraph (h) of this section and §63.1257(e)(3), and the applicable leak inspection provisions specified in §63.1258(h). This requirement is in addition to the requirements for treatment systems specified in paragraphs (g)(8) through (14) of this section. This requirement does not apply to any open biological treatment process that meets the mass removal requirements.

(6) *Residuals: general.* When residuals result from treating affected wastewater, the owner or operator shall comply with the requirements for residuals specified in paragraph (g)(14) of this section.

(7) *Treatment using a series of treatment processes.* In all cases where the wastewater provisions in this subpart allow or require the use of a treatment process or control device to comply with emissions limitations, the owner or operator may use multiple treatment processes or control devices, respectively. For combinations of treatment processes where the wastewater stream is conveyed by hard-piping, the owner or operator shall comply with either the requirements of paragraph (g)(7)(i) or (ii) of this section. For combinations of treatment processes where the wastewater stream is not conveyed by hard-piping, the owner or operator shall comply with the requirements of paragraph (g)(7)(ii) of this section. For combinations of control devices, the owner or operator shall comply with the requirements of paragraph (g)(7)(i) of this section.

(i) *Compliance across the combination of all treatment units or control devices in series.* (A) For combinations of treatment processes, the wastewater stream shall be conveyed by hard-piping between the treatment processes. For combinations of control devices, the vented gas stream shall be conveyed by hard-piping between the control devices.

(B) For combinations of treatment processes, each treatment process shall meet the applicable requirements of paragraphs (b) through (f) of this section, except as provided in paragraph (g)(3) of this section.

(C) The owner or operator shall identify, and keep a record of, the combination of treatment processes or of control devices, including identification of the first and last treatment process or control device. The owner or operator shall include this information as part of the treatment process description reported in the Notification of Compliance Status.

(D) The performance test or design evaluation shall determine compliance across the combination of treatment processes or control devices. If a performance test is conducted, the “inlet” shall be the point at which the wastewater stream or residual enters the first treatment process, or the vented gas stream enters the first control device. The “outlet” shall be the point at which the treated wastewater stream exits the last treatment process, or the vented gas stream exits the last control device.

(ii) *Compliance across individual units.* (A) For combinations of treatment processes, each treatment process shall meet the applicable requirements of paragraphs (b) through (f) of this section except as provided in paragraph (g)(3) of this section.

(B) The owner or operator shall identify, and keep a record of, the combination of treatment processes, including identification of the first and last treatment process. The owner or operator shall include this information as part of the treatment process description reported in the Notification of Compliance Status report.

(C) The owner or operator shall determine the mass removed or destroyed by each treatment process. The performance test or design evaluation shall determine compliance for the

combination of treatment processes by adding together the mass removed or destroyed by each treatment process and determine the overall control efficiency of the treatment system.

(8) *Control options: Wastewater containing partially soluble HAP compounds.* The owner or operator shall comply with either paragraph (g)(8)(i) or (ii) of this section for the control of partially soluble HAP compounds at new or existing sources.

(i) *50 ppmw concentration option.* The owner or operator shall comply with paragraphs (g)(8)(i)(A) and (B) of this section.

(A) Reduce, by removal or destruction, the concentration of total partially soluble HAP compounds to a level less than 50 ppmw as determined by the procedures specified in §63.1257(e)(2)(iii)(B).

(B) This option shall not be used when the treatment process is a biological treatment process. This option shall not be used when the wastewater is designated as an affected wastewater as specified in paragraph (a)(1)(ii) of this section. Dilution shall not be used to achieve compliance with this option.

(ii) *Percent mass removal/destruction option.* The owner or operator shall reduce, by removal or destruction, the mass of total partially soluble HAP compounds by 99 percent or more. The removal destruction efficiency shall be determined by the procedures specified in §63.1257(e)(2)(ii) or (iii)(C) for noncombustion, nonbiological treatment processes; §63.1257(e)(2)(ii) or (iii)(D) for combustion processes; §63.1257(e)(2)(iii)(F) for open biological treatment processes; and §63.1257(e)(2)(ii) or (iii)(G) for closed biological treatment processes.

(9) *Control options: Wastewater containing soluble HAP compounds.* The owner or operator shall comply with either paragraph (g)(9)(i) or (ii) of this section for the control of soluble HAP compounds at new or existing sources.

(i) *520 ppmw concentration option.* The owner or operator shall comply with paragraphs (g)(9)(i)(A) and (B) of this section.

(A) Reduce, by removal or destruction, the concentration of total soluble HAP compounds to a level less than 520 ppmw as determined in the procedures specified in §63.1257(e)(2)(iii)(B).

(B) This option shall not be used when the treatment process is a biological treatment process. This option shall not be used when the wastewater is designated as an affected wastewater as specified in paragraph (a)(1)(ii) of this section. Dilution shall not be used to achieve compliance with this option.

(ii) *Percent mass removal/destruction option.* The owner or operator shall reduce the mass of total soluble HAP by 90 percent or more, either by removal or destruction. The removal/destruction efficiency shall be determined by the procedures in §63.1257(e)(2)(ii) or (e)(2)(iii)(C) for noncombustion, nonbiological treatment processes; §63.1257(e)(2)(ii) or

(e)(2)(iii)(D) for combustion processes; §63.1257(e)(2)(iii)(F) for open biological treatment processes; and §63.1257(e)(2)(ii) or (e)(2)(iii)(G) for closed, biological treatment processes.

(10) *Control option: Enhanced biotreatment for wastewater containing soluble HAP.* The owner or operator may elect to treat affected wastewater streams containing soluble HAP in an enhanced biological treatment system, as defined in §63.1251, provided the wastewater stream contains less than 50 ppmw partially soluble HAP, or the owner or operator complies with the requirements of paragraph (g)(8) of this section before treating the affected wastewater stream in the enhanced biological treatment system. This option shall not be used when the wastewater is designated as an affected wastewater as specified in paragraph (a)(1)(ii) of this section. These treatment processes are exempt from the design evaluation or performance tests requirements specified in paragraph (g)(4) of this section.

(11) *95-percent mass reduction option, for biological treatment processes.* The owner or operator of a new or existing source using biological treatment for any affected wastewater shall reduce the mass of total soluble and partially soluble HAP sent to that biological treatment unit by at least 95 percent. All wastewater as defined in §63.1251 entering such a biological treatment unit from PMPU's subject to this subpart shall be included in the demonstration of the 95-percent mass removal. The owner or operator shall comply with paragraphs (g)(11)(i) through (iv) of this section.

(i) Except as provided in paragraph (g)(11)(iv) of this section, the owner or operator shall ensure that all wastewater from PMPU's subject to this subpart entering a biological treatment unit are treated to destroy at least 95-percent total mass of all soluble and partially soluble HAP compounds.

(ii) For open biological treatment processes, compliance shall be determined using the procedures specified in §63.1257(e)(2)(iii)(E). For closed aerobic biological treatment processes, compliance shall be determined using the procedures specified in §63.1257(e)(2)(ii), (iii)(E), or (iii)(G). For closed anaerobic biological treatment processes, compliance shall be determined using the procedures specified in §63.1257(e)(2)(ii) or (iii)(G).

(iii) For each treatment process or waste management unit that receives, manages, or treats wastewater subject to this paragraph, from the POD to the biological treatment unit, the owner or operator shall comply with paragraphs (b) through (f) of this section for control of air emissions. When complying with this paragraph, the term affected wastewater in paragraphs (b) through (f) of this section shall mean all wastewater from PMPU's, not just affected wastewater.

(iv) If wastewater is in compliance with the requirements in paragraph (g)(8), (9), or (12) of this section before entering the biological treatment unit, the hazardous air pollutants mass of that wastewater is not required to be included in the total mass flow rate entering the biological treatment unit for the purpose of demonstrating compliance.

(12) *Percent mass removal/destruction option for soluble HAP compounds at new sources.* The owner or operator of a new source shall reduce, by removal or destruction, the mass flow rate of total soluble HAP from affected wastewater by 99 percent or more. The removal/destruction

efficiency shall be determined by the procedures in §63.1257(e)(2)(ii) or (iii)(C) for noncombustion, nonbiological treatment processes; §63.1257(e)(2)(ii) and (iii)(D) for combustion processes; §63.1257(e)(2)(iii)(F) for open biological treatment processes; and §63.1257(e)(2)(ii) or (iii)(G) for closed biological treatment processes.

(13) *Treatment in a RCRA unit option.* The owner or operator shall treat the affected wastewater or residual in a unit identified in, and complying with, paragraph (g)(13)(i), (ii), or (iii) of this section. These units are exempt from the design evaluation or performance tests requirements specified in paragraph (g)(4) of this section and §63.1257(e)(2), and from the monitoring requirements specified in paragraph (a)(2)(iii) of this section, as well as recordkeeping and reporting requirements associated with monitoring and performance tests.

(i) The wastewater or residual is discharged to a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O;

(ii) The wastewater or residual is discharged to a process heater or boiler burning hazardous waste for which the owner or operator:

(A) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or

(B) Has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(iii) The wastewater or residual is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 or 40 CFR part 144 and complies with the requirements of 40 CFR part 122. The owner or operator shall comply with all applicable requirements of this subpart prior to the point where the wastewater enters the underground portion of the injection well.

(14) *Residuals.* For each residual removed from affected wastewater, the owner or operator shall control for air emissions by complying with paragraphs (b) through (f) of this section and by complying with one of the provisions in paragraphs (g)(14)(i) through (iv) of this section.

(i) Recycle the residual to a production process or sell the residual for the purpose of recycling. Once a residual is returned to a production process, the residual is no longer subject to this section.

(ii) Return the residual to the treatment process.

(iii) Treat the residual to destroy the total combined mass flow rate of soluble and/or partially soluble HAP compounds by 99 percent or more, as determined by the procedures specified in §63.1257(e)(2)(iii)(C) or (D).

(iv) Comply with the requirements for RCRA treatment options specified in paragraph (g)(13) of this section.

(h) *Control devices.* For each control device or combination of control devices used to comply with the provisions in paragraphs (b) through (f) and (g)(5) of this section, the owner or operator shall operate and maintain the control device or combination of control devices in accordance with the requirements of paragraphs (h)(1) through (5) of this section.

(1) Whenever organic HAP emissions are vented to a control device which is used to comply with the provisions of this subpart, such control device shall be operating.

(2) The control device shall be designed and operated in accordance with paragraph (h)(2) (i), (ii), (iii), (iv), or (v) of this section, as demonstrated by the provisions in §63.1257(e)(3).

(i) An enclosed combustion device (including but not limited to a vapor incinerator, boiler, or process heater) shall meet the conditions in paragraph (h)(2)(i) (A), (B), or (C) of this section, alone or in combination with other control devices. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) Reduce the organic HAP emissions vented to the control device by 95 percent by weight or greater;

(B) Achieve an outlet TOC concentration of 20 ppmv on a dry basis corrected to 3 percent oxygen. The owner or operator shall use either Method 18 of 40 CFR part 60, appendix A, or any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A of this part; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C.

(ii) A vapor recovery system (including but not limited to a carbon adsorption system or condenser), alone or in combination with other control devices, shall reduce the organic HAP emissions vented to the control device by 95 percent by weight or greater or achieve an outlet TOC concentration of 20 ppmv. The 20 ppmv performance standard is not applicable to compliance with the provisions of paragraphs (c) or (d) of this section.

(iii) A flare shall comply with the requirements of §63.11(b).

(iv) A scrubber, alone or in combination with other control devices, shall reduce the organic HAP emissions in such a manner that 95 weight-percent is either removed, or destroyed by chemical reaction with the scrubbing liquid, or achieve an outlet TOC concentration of 20 ppmv. The 20 ppmv performance standard is not applicable to compliance with the provisions of paragraphs (c) or (d) of this section.

(v) Any other control device used shall, alone or in combination with other control devices, reduce the organic HAP emissions vented to the control device by 95 percent by weight or

greater or achieve an outlet TOC concentration of 20 ppmv. The 20 ppmv performance standard is not applicable to compliance with the provisions of paragraphs (c) or (d) of this section.

(3) If the control device is a combustion device, the owner or operator shall comply with the requirements in §63.1252(g) to control halogenated vent streams.

(4) Except as provided in paragraph (i) of this section, if gaps, cracks, tears, or holes are observed in ductwork, piping, or connections to covers and control devices during an inspection, a first effort to repair shall be made as soon as practical but no later than 5 calendar days after identification. Repair shall be completed no later than 15 calendar days after identification or discovery of the defect.

(5) The provisions in paragraphs (h)(1) through (4) of this section apply at all times, except as specified in §63.1250(g). The owner or operator may not comply with the planned routine maintenance provisions in §63.1252(h) for vent streams from waste management units.

(i) *Delay of repair.* Delay of repair of equipment for which a control equipment failure or a gap, crack, tear, or hole has been identified, is allowed if the repair is technically infeasible without a shutdown, as defined in §63.1251, or if the owner or operator determines that emissions of purged material from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of this equipment shall occur by the end of the next shutdown.

(1) Delay of repair of equipment for which a control equipment failure or a gap, crack, tear, or hole has been identified, is allowed if the equipment is emptied or is no longer used to treat or manage affected wastewater or residuals removed from affected wastewater.

(2) Delay of repair of equipment for which a control equipment failure or a gap, crack, tear, or hole has been identified is also allowed if additional time is necessary due to the unavailability of parts beyond the control of the owner or operator. Repair shall be completed as soon as practical. The owner or operator who uses this provision shall comply with the requirements of §63.1259(h) to document the reasons that the delay of repair was necessary.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52607, Aug. 29, 2000; 66 FR 40133, Aug. 2, 2001; 70 FR 25670, May 13, 2005; 71 FR 20459, Apr. 20, 2006; 76 FR 22600, Apr. 21, 2011]

§63.1257 Test methods and compliance procedures.

(a) *General.* Except as specified in paragraph (a)(5) of this section, the procedures specified in paragraphs (c), (d), (e), and (f) of this section are required to demonstrate initial compliance with §§63.1253, 63.1254, 63.1256, and 63.1252(e), respectively. The provisions in paragraphs (a)(2) and (3) apply to performance tests that are specified in paragraphs (c), (d), and (e) of this section. The provisions in paragraph (a)(5) of this section are used to demonstrate initial compliance with the alternative standards specified in §§63.1253(d) and 63.1254(c). The provisions in paragraph (a)(6) of this section are used to comply with the outlet concentration requirements specified in §§63.1253(c), 63.1254(a)(2)(i), and (a)(3)(ii)(B), 63.1254(b)(i), and 63.1256(h)(2). Performance tests shall be conducted under such conditions representative of performance of the affected

source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(1) *Design evaluation.* To demonstrate that a control device meets the required control efficiency, a design evaluation must address the composition and organic HAP concentration of the vent stream entering the control device. A design evaluation also must address other vent stream characteristics and control device operating parameters as specified in any one of paragraphs (a)(1) (i) through (vi) of this section, depending on the type of control device that is used. If the vent stream is not the only inlet to the control device, the efficiency demonstration also must consider all other vapors, gases, and liquids, other than fuels, received by the control device.

(i) For an enclosed combustion device used to comply with the provisions of 63.1253 (b)(2) or (c)(2), or 63.1256(h)(2)(i)(C) with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C, the design evaluation must document that these conditions exist.

(ii) For a combustion control device that does not satisfy the criteria in paragraph (a)(1)(i) of this section, the design evaluation must document control efficiency and address the following characteristics, depending on the type of control device:

(A) For a thermal vapor incinerator, the design evaluation must consider the autoignition temperature of the organic HAP, must consider the vent stream flow rate, and must establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design evaluation shall consider the vent stream flow rate and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design evaluation shall consider the vent stream flow rate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(iii) For a condenser, the design evaluation shall consider the vent stream flow rate, relative humidity, and temperature and shall establish the design outlet organic HAP 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. The temperature of the gas stream exiting the condenser must be measured and used to establish the outlet organic HAP concentration.

(iv) For a carbon adsorption system that regenerates the carbon bed directly onsite in the control device such as a fixed-bed adsorber, the design evaluation shall consider the vent stream flow rate, 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 carbon beds, design total regeneration stream mass or volumetric 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 carbon. For vacuum desorption, the pressure drop shall be included.

(v) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design evaluation shall consider the vent stream mass or volumetric flow rate, relative humidity, and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(vi) For a scrubber, the design evaluation shall consider the vent stream composition; constituent concentrations; liquid-to-vapor ratio; scrubbing liquid flow rate and concentration; temperature; and the reaction kinetics of the constituents with the scrubbing liquid. The design evaluation shall establish the design exhaust vent stream organic compound concentration level and will include the additional information in paragraphs (a)(1)(vi)(A) and (B) of this section for trays and a packed column scrubber.

(A) Type and total number of theoretical and actual trays;

(B) Type and total surface area of packing for entire column, and for individual packed sections if column contains more than one packed section.

(2) *Calculation of TOC or total organic HAP concentration.* The TOC concentration or total organic HAP concentration is the sum of the concentrations of the individual components. If compliance is being determined based on TOC, the owner or operator shall compute TOC for each run using Equation 6 of this subpart. If compliance with the wastewater provisions is being determined based on total organic HAP, the owner or operator shall compute total organic HAP using Equation 6 of this subpart, except that only the organic HAP compounds shall be summed; when determining compliance with paragraph (e)(3)(i) of this section, only the soluble and partially soluble HAP compounds shall be summed.

$$CG_T = \frac{1}{m} \sum_{j=1}^m \left(\sum_{i=1}^n CGS_{i,j} \right) \quad (Eq. 6)$$

where:

CG_T = total concentration of TOC in vented gas stream, average of samples, dry basis, ppmv

$CGS_{i,j}$ = concentration of sample components in vented gas stream for sample j, dry basis, ppmv

i = identifier for a compound

n = number of components in the sample

j = identifier for a sample

m = number of samples in the sample run

(3) *Outlet concentration correction for supplemental gases*—(i) *Combustion devices*. Except as provided in §63.1258(b)(5)(ii)(A), for a combustion device used to comply with an outlet concentration standard, the actual TOC, organic HAP, and hydrogen halide and halogen must be corrected to 3 percent oxygen if supplemental gases, as defined in §63.1251, are added to the vent stream or manifold. The integrated sampling and analysis procedures of Method 3B of 40 CFR part 60, appendix A, shall be used to determine the actual oxygen concentration (%O_{2d}). The samples shall be taken during the same time that the TOC or total organic HAP or hydrogen halides and halogen samples are taken. The concentration corrected to 3 percent oxygen (C_c) shall be computed using Equation 7A of this subpart:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right) \quad (\text{Eq. 7A})$$

Where:

C_c = concentration of TOC or total organic HAP or hydrogen halide and halogen corrected to 3 percent oxygen, dry basis, ppmv

C_m = total concentration of TOC or total organic HAP or hydrogen halide and halogen in vented gas stream, average of samples, dry basis, ppmv

%O_{2d} = concentration of oxygen measured in vented gas stream, dry basis, percent by volume

(ii) *Noncombustion devices*. Except as provided in §63.1258(b)(5)(ii)(B), if a control device other than a combustion device is used to comply with a TOC, organic HAP, or hydrogen halide outlet concentration standard, the owner or operator must correct the actual concentration for supplemental gases using Equation 7B of this subpart; process knowledge and representative operating data may be used to determine the fraction of the total flow due to supplemental gas.

$$C_a = C_m \left(\frac{V_s + V_a}{V_a} \right) \quad (\text{Eq. 7B})$$

Where:

C_a = corrected outlet TOC, organic HAP, and hydrogen halides and halogens concentration, dry basis, ppmv

C_m = actual TOC, organic HAP, and hydrogen halides and halogens concentration measured at control device outlet, dry basis, ppmv

V_a = total volumetric flow rate of all gas streams vented to the control device, except supplemental gases

V_s = total volumetric flow rate of supplemental gases

(4) *Exemptions from compliance demonstrations.* An owner or operator using any control device specified in paragraphs (a)(4)(i) through (iv) of this section is exempt from the initial compliance provisions in paragraphs (c), (d), and (e) of this section.

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

(ii) A boiler or process heater into which the emission stream is introduced with the primary fuel.

(iii) A boiler or process heater burning hazardous waste for which the owner or operator:

(A) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or

(B) Has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(iv) A hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(5) *Initial compliance with alternative standard.* Initial compliance with the alternative standards in §§63.1253(d) and 63.1254(c) for combustion devices is demonstrated when the outlet TOC concentration is 20 ppmv or less, and the outlet hydrogen halide and halogen concentration is 20 ppmv or less. Initial compliance with the alternative standards in §§63.1253(d) and 63.1254(c) for noncombustion devices is demonstrated when the outlet TOC concentration is 50 ppmv or less, and the outlet hydrogen halide and hydrogen concentration is 50 ppmv or less. To demonstrate initial compliance, the owner or operator shall be in compliance with the monitoring provisions in §63.1258(b)(5) on the initial compliance date. The owner or operator shall use Method 18 to determine the predominant organic HAP in the emission stream if the TOC monitor is calibrated on the predominant HAP.

(6) *Initial compliance with the 20 ppmv outlet limit.* Initial compliance with the 20 ppmv TOC and hydrogen halide and halogen concentration is demonstrated when the outlet TOC concentration is 20 ppmv or less, and the outlet hydrogen halide and halogen concentration is 20 ppmv or less. To demonstrate initial compliance, the operator shall use test methods described in

paragraph (b) of this section. The owner or operator shall comply with the monitoring provisions in §63.1258(b)(1) through (4) on the initial compliance date.

(b) *Test methods.* When testing is conducted to measure emissions from an affected source, the test methods specified in paragraphs (b)(1) through (10) of this section shall be used.

(1) EPA Method 1 or 1A of appendix A of part 60 is used for sample and velocity traverses.

(2) EPA Method 2, 2A, 2C, or 2D of appendix A of part 60 is used for velocity and volumetric flow rates.

(3) EPA Method 3 of appendix A of part 60 is used for gas analysis.

(4) EPA Method 4 of appendix A of part 60 is used for stack gas moisture.

(5) [Reserved]

(6) The following methods are specified for concentration measurements:

(i) Method 18 may be used to determine HAP concentration in any control device efficiency determination.

(ii) Method 25 of appendix A of part 60 may be used to determine total gaseous nonmethane organic concentration for control efficiency determinations in combustion devices.

(iii) Method 26 or 26A of appendix A of part 60 shall be used to determine hydrogen chloride, hydrogen halide and halogen concentrations in control device efficiency determinations or in the 20 ppmv outlet hydrogen halide concentration standard.

(iv) Method 25A of appendix A of part 60 may be used to determine the HAP or TOC concentration for control device efficiency determinations under the conditions specified in Method 25 of appendix A for direct measurement of an effluent with a flame ionization detector, or in demonstrating compliance with the 20 ppmv TOC outlet standard. If Method 25A is used to determine the concentration of TOC for the 20 ppmv standard, the instrument shall be calibrated on methane or the predominant HAP. If calibrating on the predominant HAP, the use of Method 25A shall comply with paragraphs (b)(6)(iv)(A) through (C) of this section.

(A) The organic HAP used as the calibration gas for Method 25A, 40 CFR part 60, appendix A, shall be the single organic HAP representing the largest percent by volume.

(B) The use of Method 25A, 40 CFR part 60, appendix A, is acceptable if the response from the high level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(C) The span value of the analyzer must be less than 100 ppmv.

(7) *Testing conditions for continuous processes.* Testing of emissions on equipment operating as part of a continuous process will consist of three 1-hour runs. Gas stream volumetric flow rates shall be measured every 15 minutes during each 1-hour run. The HAP concentration shall be determined from samples collected in an integrated sample over the duration of each 1-hour test run, or from grab samples collected simultaneously with the flow rate measurements (every 15 minutes). If an integrated sample is collected for laboratory analysis, the sampling rate shall be adjusted proportionally to reflect variations in flow rate. For continuous gas streams, the emission rate used to determine compliance shall be the average emission rate of the three test runs.

(8) *Testing and compliance determination conditions for batch processes.* Testing of emissions on equipment where the flow of gaseous emissions is intermittent (batch operations) shall be conducted as specified in paragraphs (b)(8)(i) through (iii) of this section.

(i) Except as provided in paragraph (b)(9) of this section for condensers, testing shall be conducted at absolute worst-case conditions or hypothetical worst-case conditions. Gas stream volumetric flow rates shall be measured at 15-minute intervals. The HAP or TOC concentration shall be determined from samples collected in an integrated sample over the duration of the test, or from grab samples collected simultaneously with the flow rate measurements (every 15 minutes). If an integrated sample is collected for laboratory analysis, the sampling rate shall be adjusted proportionally to reflect variations in flow rate. The absolute worst-case or hypothetical worst-case conditions shall be characterized by the criteria presented in paragraphs (b)(8)(i)(A) and (B) of this section. In all cases, a site-specific plan shall be submitted to the Administrator for approval prior to testing in accordance with §63.7(c) and §63.1260(l). The test plan shall include the emission profile described in paragraph (b)(8)(ii) of this section.

(A) Absolute worst-case conditions are defined by the criteria presented in paragraph (b)(8)(i)(A)(1) or (2) of this section if the maximum load is the most challenging condition for the control device. Otherwise, absolute worst-case conditions are defined by the conditions in paragraph (b)(8)(i)(A)(3) of this section. The owner or operator must consider all relevant factors, including load and compound-specific characteristics in defining absolute worst-case conditions.

(1) The period in which the inlet to the control device will contain at least 50 percent of the maximum HAP load (in lb) capable of being vented to the control device over any 8 hour period. An emission profile as described in paragraph (b)(8)(ii)(A) of this section shall be used to identify the 8-hour period that includes the maximum projected HAP load.

(2) A 1-hour period of time in which the inlet to the control device will contain the highest HAP mass loading rate, in lb/hr, capable of being vented to the control device. An emission profile as described in paragraph (b)(8)(ii)(A) of this section shall be used to identify the 1-hour period of maximum HAP loading.

(3) The period of time when the HAP loading or stream composition (including non-HAP) is most challenging for the control device. These conditions include, but are not limited to the following:

(i) Periods when the stream contains the highest combined VOC and HAP load, in lb/hr, described by the emission profiles in paragraph (b)(8)(ii) of this section;

(ii) Periods when the streams contain HAP constituents that approach limits of solubility for scrubbing media;

(iii) Periods when the streams contain HAP constituents that approach limits of adsorptivity for carbon adsorption systems.

(B) Hypothetical worst-case conditions are simulated test conditions that, at a minimum, contain the highest hourly HAP load of emissions that would be predicted to be vented to the control device from the emissions profile described in paragraph (b)(8)(ii)(B) or (C) of this section.

(ii) *Emissions profile.* The owner or operator may choose to perform tests only during those periods of the worst-case conditions that the owner or operator selects to control as part of achieving the required emission reduction. The owner or operator must develop an emission profile for the vent to the control device that describes the characteristics of the vent stream at the inlet to the control device under worst case conditions. The emission profile shall be developed based on any one of the procedures described in (b)(8)(ii)(A) through (C) of this section, as required by paragraph (b)(8)(i).

(A) *Emission profile by process.* The emission profile must consider all emission episodes that could contribute to the vent stack for a period of time that is sufficient to include all processes venting to the stack and shall consider production scheduling. The profile shall describe the HAP load to the device that equals the highest sum of emissions from the episodes that can vent to the control device in any given hour. Emissions per episode shall be calculated using the procedures specified in paragraph (d)(2) of this section. Emissions per episode shall be divided by the duration of the episode only if the duration of the episode is longer than 1 hour.

(B) *Emission profile by equipment.* The emission profile must consist of emissions that meet or exceed the highest emissions, in lb/hr, that would be expected under actual processing conditions. The profile shall describe equipment configurations used to generate the emission events, volatility of materials processed in the equipment, and the rationale used to identify and characterize the emission events. The emissions may be based on using a compound more volatile than compounds actually used in the process(es), and the emissions may be generated from all equipment in the process(es) or only selected equipment.

(C) *Emission profile by capture and control device limitation.* The emission profile shall consider the capture and control system limitations and the highest emissions, in lb/hr, that can be routed to the control device, based on maximum flowrate and concentrations possible because of limitations on conveyance and control equipment (e.g., fans, LEL alarms and safety bypasses).

(iii) Three runs, at a minimum of 1 hour each and a maximum of 8 hours each, are required for performance testing. Each run must occur over the same worst-case conditions, as defined in paragraph (b)(8)(i) of this section.

(9) *Testing requirements for condensers.* For emission streams controlled using condensers, continuous direct measurement of condenser outlet gas temperature to be used in determining concentrations per the design evaluation described in §63.1257(a)(1)(iii) is required.

(10) *Wastewater testing.* Wastewater analysis shall be conducted in accordance with paragraph (b)(10)(i), (ii), (iii), (iv), or (v) of this section.

(i) *Method 305.* Use procedures specified in Method 305 of 40 CFR part 63, appendix A, and comply with requirements specified in paragraph (b)(10)(vi) of this section.

(ii) *EPA Method 624, 625, 1624, 1625, 1666, or 1671.* Use procedures specified in EPA Method 624, 625, 1624, 1625, 1666, or 1671 of 40 CFR part 136, appendix A, and comply with requirements in paragraph (b)(10)(vi) of this section.

(iii) *Method 8260 or 8270.* Use procedures specified in Method 8260 or 8270 in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846, Third Edition, September 1986, as amended by Update I, November 15, 1992. As an alternative, an owner or operator may use any more recent, updated version of Method 8260 or 8270 approved by the EPA. For the purpose of using Method 8260 or 8270 to comply with this subpart, the owner or operator must maintain a formal quality assurance program consistent with either Section 8 of Method 8260 or Method 8270, and this program must include the following elements related to measuring the concentrations of volatile compounds:

(A) Documentation of site-specific procedures to minimize the loss of compounds due to volatilization, biodegradation, reaction, or sorption during the sample collection, storage, and preparation steps.

(B) Documentation of specific quality assurance procedures followed during sampling, sample preparation, sample introduction, and analysis.

(C) Measurement of the average accuracy and precision of the specific procedures, including field duplicates and field spiking of the material source before or during sampling with compounds having similar chemical characteristics to the target analytes.

(iv) *Other EPA methods.* Use procedures specified in the method, validate the method using the procedures in paragraph (b)(10)(iv)(A) or (B) of this section, and comply with the procedures in paragraph (b)(10)(vi) of this section.

(A) Validate the method according to section 5.1 or 5.3 of Method 301 of 40 CFR part 63, appendix A.

(B) Follow the procedure as specified in “Alternative Validation Procedure for EPA Waste Methods” 40 CFR part 63, appendix D.

(v) *Methods other than an EPA method.* Use procedures specified in the method, validate the method using the procedures in paragraph (b)(10)(iv)(A) of this section, and comply with the requirements in paragraph (b)(10)(vi) of this section.

(vi) *Sampling plan.* The owner or operator shall prepare a sampling plan. Wastewater samples shall be collected using sampling procedures which minimize loss of organic compounds during sample collection and analysis and maintain sample integrity. The sample plan shall include procedures for determining recovery efficiency of the relevant partially soluble and soluble HAP compounds. An example of an acceptable sampling plan would be one that incorporates similar sampling and sample handling requirements to those of Method 25D of 40 CFR part 60, appendix A. The sampling plan shall be maintained at the facility.

(c) *Initial compliance with storage tank provisions.* The owner or operator of an affected storage tank shall demonstrate initial compliance with §63.1253(b) or (c), as applicable, by fulfilling the requirements of paragraph (c)(1), or (c)(2), or (c)(3) of this section.

(1) *Performance test.* If this option is chosen to demonstrate initial compliance with the percent reduction requirement of §63.1253(b)(1) or (c)(1)(i), the efficiency of the control device shall be calculated using performance test data as specified in paragraphs (c)(1)(i) through (iii) of this section. To demonstrate initial compliance with the outlet concentration requirements in §63.1253(b)(2) and (c)(2), the owner or operator must conduct a performance test and fulfill the requirements of paragraph (a)(6) of this section.

(i) Equations 8 and 9 of this subpart shall be used to calculate the mass rate of total HAP reasonably expected maximum filling rate at the inlet and outlet of the control device for standard conditions of 20 °C: where:

$$E_i = K_2 \left(\sum_{j=1}^n C_{ij} M_{ij} \right) Q_i \quad (Eq. 8)$$

$$E_o = K_2 \left(\sum_{j=1}^n C_{oj} M_{oj} \right) Q_o \quad (Eq. 9)$$

where:

C_{ij} , C_{oj} = concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, ppmv

E_i , E_o = mass rate of total HAP at the inlet and outlet of the control device, respectively, dry basis, kg/hr

M_{ij} , M_{oj} = molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole

Q_i , Q_o = flow rate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute

K_2 = constant, 2.494×10^{-6} (parts per million) $^{-1}$ (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature is 20 °C

n = number of sample components in the gas stream

(ii) The percent reduction in total HAP shall be calculated using Equation 10 of this subpart:

$$R = \frac{E_i - E_o}{E_i} (100) \quad (Eq. 10)$$

where:

R = control efficiency of control device, percent

E_i = mass rate of total HAP at the inlet to the control device as calculated under paragraph (c)(1)(i) of this section, kilograms organic HAP per hour

E_o = mass rate of total HAP at the outlet of the control device, as calculated under paragraph (c)(1)(i) of this section, kilograms organic HAP per hour

(iii) A performance test is not required to be conducted if the control device used to comply with §63.1253 (storage tank provisions) is also used to comply with §63.1254 (process vent provisions), and compliance with §63.1254 has been demonstrated in accordance with paragraph (d) of this section.

(2) *Design evaluation.* If this option is chosen to demonstrate initial compliance with the percent reduction requirement of §63.1253(b) or (c), a design evaluation shall be prepared in accordance with the provisions in paragraph (a)(1) of this section. The design evaluation shall include documentation demonstrating that the control device being used achieves the required control efficiency during reasonably expected maximum filling rate.

(3) *Floating roof.* If the owner or operator of an affected source chooses to comply with the provisions of §63.1253(b) or (c) by installing a floating roof, the owner or operator shall comply with the procedures described in §§63.119(b), (c), (d), and 63.120(a), (b), and (c), with the differences noted in paragraphs (c)(3)(i) through (v) of this section for the purposes of this subpart.

(i) When the term “storage vessel” is used in §§63.119 and 63.120, the definition of “storage tank” in §63.1251 shall apply for the purposes of this subpart.

(ii) When December 31, 1992 is referred to in §63.119, April 2, 1997 shall apply instead for the purposes of this subpart.

(iii) When April 22, 1994 is referred to in §63.119, September 21, 1998 shall apply instead for the purposes of this subpart.

(iv) When the phrase “the compliance date specified in §63.100 of subpart F of this part” is referred to in §63.120, the phrase “the compliance date specified in §63.1250” shall apply for the purposes of this subpart.

(v) When the phrase “the maximum true vapor pressure of the total organic HAP's in the stored liquid falls below the values defining Group 1 storage vessels specified in table 5 or table 6 of this subpart” is referred to in §63.120(b)(1)(iv), the phrase “the maximum true vapor pressure of the total organic HAP in the stored liquid falls below 13.1 kPa” shall apply for the purposes of this subpart.

(4) *Initial compliance with alternative standard.* Initial compliance with §63.1253(d) is demonstrated by fulfilling the requirements of paragraph (a)(5) of this section.

(5) *Planned maintenance.* The owner or operator shall demonstrate compliance with the requirements of §63.1253(e) by including the periods of planned routine maintenance specified by date and time in each Periodic Report required by §63.1260.

(d) *Initial compliance with process vent provisions.* An owner or operator of an affected source complying with the process vent standards in §63.1254 shall demonstrate compliance using the procedures described in paragraphs (d)(1) through (4) of this section.

(1) Except as provided in paragraph (a)(4) of this section, initial compliance with the process vent standards in §63.1254 shall be demonstrated using the procedures specified in paragraphs (d)(1)(i) through (iv), as applicable.

(i) Initial compliance with §63.1254(a)(2)(i) is demonstrated when the actual emissions of HAP from the sum of all process vents within a process is less than or equal to 900 kg/yr. Initial compliance with §63.1254(a)(2)(ii) is demonstrated when the actual emissions of HAP from the sum of all process vents in compliance with §63.1254(a)(2)(i) is less than or equal to 1,800 kg/yr. Uncontrolled HAP emissions and controlled HAP emissions shall be determined using the procedures described in paragraphs (d)(2) and (3) of this section. Controlled emissions during periods of planned routine maintenance of a CCCD as specified in §63.1252(h), must be calculated assuming the HAP emissions are reduced by 93 percent.

(ii) Initial compliance with the percent reduction requirements in §63.1254(a)(1)(i), (a)(3), and (b) is demonstrated by:

(A) Determining controlled HAP emissions using the procedures described in paragraph (d)(3) of this section, and uncontrolled HAP emissions determined using the procedures described in paragraph (d)(2) of this section, and demonstrating that the reductions required by §63.1254(a)(1)(i), (a)(3), and (b) are met; or

(B) Controlling the process vents using a device meeting the criteria specified in paragraph (a)(4) of this section.

(iii) Initial compliance with the outlet concentration requirements in §63.1254(a)(1)(ii)(A), (a)(3), and (b)(1) is demonstrated when the outlet TOC concentration is 20 ppmv or less and the outlet hydrogen halide and halogen concentration is 20 ppmv or less. The owner or operator shall demonstrate compliance by fulfilling the requirements in paragraph (a)(6) of this section.

(iv) Initial compliance with §63.1254(c) is demonstrated by fulfilling the requirements of paragraph (a)(5) of this section.

(2) *Uncontrolled emissions.* An owner or operator of an affected source complying with the emission limitation required by §63.1254(a)(1), or emissions reductions specified in §63.1254(a)(2), (a)(3), or (b), for each process vent within a process, shall calculate uncontrolled emissions from all equipment in the process according to the procedures described in paragraph (d)(2)(i) or (ii) of this section, as appropriate.

(i) *Emission estimation procedures.* Owners or operators shall determine uncontrolled emissions of HAP using measurements and/or calculations for each batch emission episode within each unit operation according to the engineering evaluation methodology in paragraphs (d)(2)(i)(A) through (H) of this section. Except where variations are noted, individual HAP partial pressures in multicomponent systems shall be determined by the following methods: If the components are miscible in one another, use Raoult's law to calculate the partial pressures; if the solution is a dilute aqueous mixture, use Henry's law to calculate partial pressures; if Raoult's law or Henry's law are not appropriate or available, use experimentally obtained activity coefficients or models such as the group-contribution models, to predict activity coefficients, or assume the components of the system behave independently and use the summation of all vapor pressures from the HAP as the total HAP partial pressure. Chemical property data can be obtained from standard reference texts.

(A) *Vapor displacement.* Emissions from vapor displacement due to transfer of material shall be calculated using Equation 11 of this subpart. The individual HAP partial pressures may be calculated using Raoult's law.

$$E = \frac{(V)}{(R)(T)} \times \sum_{i=1}^n (P_i)(MW_i) \quad (Eq. 11)$$

where:

E = mass of HAP emitted

V = volume of gas displaced from the vessel

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i = partial pressure of the individual HAP

MW_i = molecular weight of the individual HAP

n = number of HAP compounds in the emission stream i = identifier for a HAP compound

(B) *Purging*. Emissions from purging shall be calculated using Equation 12 of this subpart. The partial pressures of individual condensable compounds may be calculated using Raoult's law, the pressure of the vessel vapor space may be set equal to 760 mmHg, and the partial pressure of HAP shall be assumed to be 25 percent of the saturated value if the purge flow rate is greater than 100 standard cubic feet per minute (scfm).

$$E = \sum_{i=1}^n P_i MW_i \times \frac{(V)(t)}{(R)(T)} \times \frac{P_T}{P_T - \sum_{j=1}^m (P_j)} \quad (Eq. 12)$$

Where:

E = mass of HAP emitted

V = purge flow rate at the temperature and pressure of the vessel vapor space

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i = partial pressure of the individual HAP

P_j = partial pressure of individual condensable VOC compounds (including HAP)

P_T = pressure of the vessel vapor space

MW_i = molecular weight of the individual HAP

t = time of purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

j = identifier for a condensable compound

m = number of condensable compounds (including HAP) in the emission stream

(C) *Heating*. Emissions caused by the heating of a vessel to a temperature equal to or lower than 10 K below the boiling point shall be calculated using the procedures in either paragraph (d)(2)(i)(C)(1) or (3) of this section. Emissions caused by heating a vessel to a temperature that is higher than 10 K below the boiling point and less than the boiling point, must be calculated using the procedures in either paragraph (d)(2)(i)(C) (2) or (3) of this section. If the contents of a vessel are heated to the boiling point, emissions must be calculated using the procedures in paragraph (d)(2)(i)(C)(4) of this section.

(1) This paragraph describes procedures to calculate emissions if the final temperature to which the vessel contents are heated is 10 K below the boiling point of the HAP in the vessel, or lower. The owner or operator shall calculate the mass of HAP emitted per episode using either Equation 13 or 14 of this subpart. The moles of noncondensable gas displaced are calculated using Equation 15 of this subpart. The initial and final pressure of the noncondensable gas in the vessel shall be calculated using Equation 16 of this subpart. The average molecular weight of HAP in the displaced gas shall be calculated using Equation 17 of this subpart.

$$E = \frac{\sum_{i=1}^n ((P_i^*)(x_i)(MW_i))}{760 - \sum_{j=1}^m ((P_j^*)(x_j))} \times \Delta\eta \quad (\text{Eq. 13})$$

$$E = \frac{\frac{\sum_{i=1}^n (P_i)_{T1}}{Pa_1} + \frac{\sum_{i=1}^n (P_i)_{T2}}{Pa_2}}{2} \times \Delta\eta \times MW_{HAP} \quad (\text{Eq. 14})$$

$$\Delta\eta = \frac{V}{R} \left[\left(\frac{Pa_1}{T_1} \right) - \left(\frac{Pa_2}{T_2} \right) \right] \quad (\text{Eq. 15})$$

$$Pa_n = P_{atm} - \sum_{j=1}^m (P_j)_{Tn} \quad (\text{Eq. 16})$$

$$MW_{HAP} = \frac{\sum_{i=1}^n \left((P_i)_{T_1} + (P_i)_{T_2} \right) MW_i}{\sum_{i=1}^n \left((P_i)_{T_1} + (P_i)_{T_2} \right)} \quad (Eq. 17)$$

Where:

E = mass of HAP vapor displaced from the vessel being heated

x_i = mole fraction of each HAP in the liquid phase

x_j = mole fraction of each condensable VOC (including HAP) in the liquid phase

P_i^* = vapor pressure of each HAP in the vessel headspace at any temperature between the initial and final heatup temperatures, mmHg.

P_j^* = vapor pressure of each condensable VOC (including HAP) in the vessel headspace at any temperature between the initial and final heatup temperatures, mmHg.

760 = atmospheric pressure, mmHg

MW_{HAP} = the average molecular weight of HAP present in the displaced gas

$\Delta\eta$ = number of moles of noncondensable gas displaced

V = volume of free space in the vessel

R = ideal gas law constant

T_1 = initial temperature of vessel contents, absolute

T_2 = final temperature of vessel contents, absolute

P_{a_n} = partial pressure of noncondensable gas in the vessel headspace at initial (n = 1) and final (n = 2) temperature

P_{atm} = atmospheric pressure (when $\Delta\eta$ is used in Equation 13 of this subpart, P_{atm} may be set equal to 760 mmHg for any vessel)

$(P_j)_{T_n}$ = partial pressure of each condensable compound (including HAP) in the vessel headspace at the initial temperature (n = 1) and final (n = 2) temperature

m = number of condensable compounds (including HAP) in the displaced vapor

j = identifier for a condensable compound

(P_i)_{Tn} = partial pressure of each HAP in the vessel headspace at initial (T₁) and final (T₂) temperature

MW_i = molecular weight of the individual HAP

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(2) If the vessel contents are heated to a temperature that is higher than 10 K below the boiling point and less than the boiling point, emissions must be calculated using the procedures in paragraph (d)(2)(i)(C)(2)(i), or (ii), or (iii) of this section.

(i) Use Equation 13 of this subpart. In Equation 13 of this subpart, the HAP vapor pressures must be determined at the temperature 10 K below the boiling point. In the calculation of $\Delta\eta$ for Equation 13 of this subpart, T₂ must be the temperature 10 K below the boiling point, and Pa₂ must be determined at the temperature 10 K below the boiling point.

(ii) Use Equation 14 of this subpart. In Equation 14 of this subpart, the HAP partial pressures must be determined at the temperature 10 K below the boiling point. In the calculation of $\Delta\eta$ for Equation 14 of this subpart, T₂ must be the temperature 10 K below the boiling point, and Pa₂ must be determined at the temperature 10 K below the boiling point. In the calculation of MW_{HAP}, the HAP partial pressures must be determined at the temperature 10 K below the boiling point.

(iii) Use Equation 14 of this subpart over specific temperature increments. If the initial temperature is lower than 10 K below the boiling point, emissions must be calculated as the sum over two increments; one increment is from the initial temperature to 10 K below the boiling point, and the second is from 10 K below the boiling point to the lower of either the final temperature or the temperature 5 K below the boiling point. If the initial temperature is higher than 10 K below the boiling point, emissions are calculated over one increment from the initial temperature to the lower of either the final temperature or the temperature 5 K below the boiling point.

(3)(i) Emissions caused by heating a vessel are calculated using Equation 18 of this subpart.

$$E = MW_{HAP} \times \left(N_{avg} \times \ln \left(\frac{P_T - \sum_{j=1}^n (P_{j,1})}{P_T - \sum_{j=1}^n (P_{j,2})} \right) - (n_{j,2} - n_{j,1}) \right) \quad (Eq. 18)$$

Where:

E = mass of HAP vapor displaced from the vessel being heated

N_{avg} = average gas space molar volume during the heating process

P_T = total pressure in the vessel

$P_{i,1}$ = partial pressure of the individual HAP compounds at T_1

$P_{i,2}$ = partial pressure of the individual HAP compounds at T_2

MW_{HAP} = average molecular weight of the HAP compounds

$n_{i,1}$ = number of moles of condensable in the vessel headspace at T_1

$n_{i,2}$ = number of moles of condensable in the vessel headspace at T_2

n = number of HAP compounds in the emission stream

(ii) The average gas space molar volume during the heating process is calculated using Equation 19 of this subpart.

$$N_{avg} = \frac{VP_T}{2R} \left(\frac{1}{T_1} + \frac{1}{T_2} \right) \quad (Eq. 19)$$

Where:

N_{avg} = average gas space molar volume during the heating process

V = volume of free space in vessel

P_T = total pressure in the vessel

R = ideal gas law constant

T_1 = initial temperature of the vessel

T_2 = final temperature of the vessel

(iii) The difference in the number of moles of condensable in the vessel headspace between the initial and final temperatures is calculated using Equation 20 of this subpart.

$$(n_{i,2} - n_{i,1}) = \frac{V}{(R)(T_2)} \sum_{i=1}^n P_{i,2} - \frac{V}{(R)(T_1)} \sum_{i=1}^n P_{i,1} \quad (Eq. 20)$$

Where:

V = volume of free space in vessel

R = ideal gas law constant

T₁ = initial temperature in the vessel

T₂ = final temperature in the vessel

P_{i,1} = partial pressure of the individual HAP compounds at T₁

P_{i,2} = partial pressure of the individual HAP compounds at T₂

n = number of HAP compounds in the emission stream

(4) If the vessel contents are heated to the boiling point, emissions must be calculated using the procedure in paragraphs (d)(2)(i)(C)(4)(i) and (ii) of this section.

(i) Use either of the procedures in paragraph (d)(3)(i)(B)(3) of this section to calculate the emissions from heating to the boiling point (note that Pa₂ = 0 in the calculation of Δη); and

(ii) While boiling, the vessel must be operated with a properly operated process condenser. An initial demonstration that a process condenser is properly operated is required for some process condensers, as described in paragraph (d)(3)(iii) of this section.

(D) *Depressurization*. Emissions from depressurization shall be calculated using the procedures in either paragraphs (d)(2)(i)(D)(1) through (4), paragraphs (d)(2)(i)(D)(5) through (9), or paragraph (d)(2)(i)(D)(10) of this section.

(1) Equations 21 and 22 of this subpart are used to calculate the initial and final volumes of noncondensable gas present in the vessel, adjusted to atmospheric pressure. The HAP partial pressures may be calculated using Raoult's law.

$$V_{nc1} = \frac{VP_{nc1}}{760} \quad (Eq. 21)$$

$$V_{nc2} = \frac{VP_{nc2}}{760} \quad (Eq. 22)$$

Where:

V_{nc1} = initial volume of noncondensable gas in the vessel

V_{nc2} = final volume of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1} = initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart, mmHg

P_{nc2} = final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart, mmHg

760 = atmospheric pressure, mmHg

(2) The initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 23 and 24 of this subpart:

$$P_{nc1} = P_1 - \sum_{j=1}^m (P_j^*)(x_j) \quad (Eq. 23)$$

$$P_{nc2} = P_2 - \sum_{j=1}^m (P_j^*)(x_j) \quad (Eq. 24)$$

Where:

P_{nc1} = initial partial pressure of the noncondensable gas

P_{nc2} = final partial pressure of the noncondensable gas

P_1 = initial vessel pressure

P_2 = final vessel pressure

P_j^* = vapor pressure of each condensable (including HAP) in the emission stream

x_j = mole fraction of each condensable (including HAP) in the liquid phase

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(3) The average ratio of moles of noncondensable to moles of an individual HAP in the emission stream is calculated using Equation 25 of this subpart; this calculation must be repeated for each HAP in the emission stream:

$$n_{Ri} = \frac{\left(\frac{P_{nc1}}{(P_i^*)(x_i)} + \frac{P_{nc2}}{(P_i^*)(x_i)} \right)}{2} \quad (\text{Eq. 25})$$

Where:

n_{Ri} = average ratio of moles of noncondensable to moles of individual HAP

P_{nc1} = initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart

P_{nc2} = final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart

P_i^* = vapor pressure of each individual HAP

x_i = mole fraction of each individual HAP in the liquid phase.

n = number of HAP compounds

i = identifier for a HAP compound

(4) The mass of HAP emitted shall be calculated using Equation 26 of this subpart:

$$E = (V_{nc1} - V_{nc2}) \times \frac{P_{atm}}{RT} \times \sum_{i=1}^n \frac{MW_i}{n_{Ri}} \quad (\text{Eq. 26})$$

Where:

E = mass of HAP emitted

V_{nc1} = initial volume of noncondensable gas in the vessel, as calculated using Equation 21 of this subpart

V_{nc2} = final volume of noncondensable gas in the vessel, as calculated using Equation 22 of this subpart

n_{Ri} = average ratio of moles of noncondensable to moles of individual HAP, as calculated using Equation 25 of this subpart

P_{atm} = atmospheric pressure, standard

R = ideal gas law constant

T = temperature of the vessel, absolute

MW_i = molecular weight of each HAP

(5) The moles of HAP vapor initially in the vessel are calculated using the ideal gas law using Equation 27 of this subpart:

$$n_{HAP} = \frac{(Y_{HAP})(V)(P_1)}{RT} \quad (Eq. 27)$$

Where:

Y_{HAP} = mole fraction of HAP (the sum of the individual HAP fractions, ΣY_i)

V = free volume in the vessel being depressurized

P_1 = initial vessel pressure

R = ideal gas law constant

T = vessel temperature, absolute

(6) The initial and final moles of noncondensable gas present in the vessel are calculated using Equations 28 and 29 of this subpart:

$$n_1 = \frac{VP_{n1}}{RT} \quad (Eq. 28)$$

$$n_2 = \frac{VP_{n2}}{RT} \quad (Eq. 29)$$

Where:

n_1 = initial number of moles of noncondensable gas in the vessel

n_2 = final number of moles of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1} = initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart

P_{nc2} = final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart

R = ideal gas law constant

T = temperature, absolute

(7) The initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 23 and 24 of this subpart.

(8) The moles of HAP emitted during the depressurization are calculated by taking an approximation of the average ratio of moles of HAP to moles of noncondensable and multiplying by the total moles of noncondensables released during the depressurization, using Equation 30 of this subpart:

$$n_{HAP} = \left[\frac{\frac{n_{HAP,1}}{n_1} + \frac{n_{HAP,2}}{n_2}}{2} \right] [n_1 - n_2] \quad (Eq. 30)$$

where:

n_{HAP} = moles of HAP emitted

n_1 = initial number of moles of noncondensable gas in the vessel, as calculated using Equation 28 of this subpart

n_2 = final number of moles of noncondensable gas in the vessel, as calculated using Equation 29 of this subpart

(9) The mass of HAP emitted can be calculated using Equation 31 of this subpart:

$$E = \eta_{HAP} * MW_{HAP} \quad (Eq. 31)$$

where:

E = mass of HAP emitted

η_{HAP} = moles of HAP emitted, as calculated using Equation 30 of this subpart

MW_{HAP} = average molecular weight of the HAP as calculated using Equation 17 of this subpart

(10) Emissions from depressurization may be calculated using equation 32 of this subpart:

$$E = \frac{V}{(R)(T)} \times \ln \left(\frac{P_1 - \sum_{j=1}^m (P_j)}{P_2 - \sum_{j=1}^m (P_j)} \right) \times \sum_{i=1}^n (P_i)(\text{MW}_i) \quad (\text{Eq. 32})$$

Where:

V = free volume in vessel being depressurized

R = ideal gas law constant

T = temperature of the vessel, absolute

P_1 = initial pressure in the vessel

P_2 = final pressure in the vessel

P_j = partial pressure of the individual condensable compounds (including HAP)

MW_i = molecular weight of the individual HAP compounds

n = number of HAP compounds in the emission stream

m = number of condensable compounds (including HAP) in the emission stream

i = identifier for a HAP compound

j = identifier for a condensable compound.

(E) *Vacuum systems.* Emissions from vacuum systems may be calculated using Equation 33 of this subpart if the air leakage rate is known or can be approximated. The individual HAP partial pressures may be calculated using Raoult's Law.

$$E = \frac{(La)(t)}{MW_{nc}} \left(\frac{\sum_{i=1}^n P_i MW_i}{P_{system} - \sum_{j=1}^m P_j} \right) \quad (\text{Eq. 33})$$

Where:

E = mass of HAP emitted

P_{system} = absolute pressure of receiving vessel or ejector outlet conditions, if there is no receiver

P_i = partial pressure of the HAP at the receiver temperature or the ejector outlet conditions

P_j = partial pressure of condensable (including HAP) at the receiver temperature or the ejector outlet conditions

La = total air leak rate in the system, mass/time

MW_{nc} = molecular weight of noncondensable gas

t = time of vacuum operation

MW_i = molecular weight of the individual HAP in the emission stream, with HAP partial pressures calculated at the temperature of the receiver or ejector outlet, as appropriate

(F) *Gas evolution*. Emissions from gas evolution shall be calculated using Equation 12 of this subpart with V calculated using Equation 34 of this subpart:

$$V = \frac{(W_g)(R)(T)}{(P_r)(MW_g)} \quad (\text{Eq. 34})$$

Where:

V = volumetric flow rate of gas evolution

W_g = mass flow rate of gas evolution

R = ideal gas law constant

T = temperature at the exit, absolute

P_T = vessel pressure

MW_g = molecular weight of the evolved gas

(G) *Air drying*. Emissions from air drying shall be calculated using Equation 35 of this subpart:

$$E = B \times \left(\frac{PS_1}{100 - PS_1} - \frac{PS_2}{100 - PS_2} \right) \quad (Eq. 35)$$

Where:

E = mass of HAP emitted

B = mass of dry solids

PS_1 = HAP in material entering dryer, weight percent

PS_2 = HAP in material exiting dryer, weight percent

(H) *Empty vessel purging*. Emissions from empty vessel purging shall be calculated using Equation 36 of this subpart (Note: The term $e^{-Pt/v}$ can be assumed to be 0):

$$E = \left(\frac{V}{RT} \times \left(\sum_{i=1}^n (P_i)(MW_i) \right) \right) (1 - e^{-Pt/v}) \quad (Eq. 36)$$

Where:

V = volume of empty vessel

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i = partial pressure of the individual HAP at the beginning of the purge

(MW_i) = molecular weight of the individual HAP

F = flowrate of the purge gas

t = duration of the purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(ii) *Engineering assessments.* The owner or operator shall conduct an engineering assessment to calculate uncontrolled HAP emissions for each emission episode that is not due to vapor displacement, purging, heating, depressurization, vacuum operations, gas evolution, or air drying. For emission episodes caused by any of these types of activities, the owner or operator also may calculate uncontrolled HAP emissions based on an engineering assessment if the owner or operator can demonstrate to the Administrator that the methods in paragraph (d)(2)(i) of this section are not appropriate. Modified versions of the engineering evaluation methods in paragraphs (d)(2)(i)(A) through (H) may be used if the owner or operator demonstrates that they have been used to meet other regulatory obligations, and they do not affect applicability assessments or compliance determinations under this subpart GGG. One criterion the owner or operator could use to demonstrate that the methods in paragraph (d)(2)(i) of this section are not appropriate is if previous test data are available that show a greater than 20 percent discrepancy between the test value and the estimated value. An engineering assessment includes, but is not limited to, the following:

(A) Previous test results, provided the tests are representative of current operating practices at the process unit.

(B) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(C) Maximum flow rate, HAP emission rate, concentration, or other relevant parameter specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(1) Use of material balances based on process stoichiometry to estimate maximum organic HAP concentrations.

(2) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities.

(3) Estimation of HAP concentrations based on saturation conditions.

(E) All data, assumptions, and procedures used in the engineering assessment shall be documented in accordance with §63.1260(e). Data or other information supporting a finding that the emissions estimation equations are inappropriate shall be reported in the Precompliance report.

(3) *Controlled emissions.* An owner or operator shall determine controlled emissions using the procedures in either paragraph (d)(3)(i) or (ii) of this section.

(i) *Small control devices.* Except for condensers, controlled emissions for each process vent that is controlled using a small control device shall be determined by using the design evaluation described in paragraph (d)(3)(i)(A) of this section, or conducting a performance test in accordance with paragraph (d)(3)(ii) of this section. Whenever a small control device becomes a large control device, the owner or operator must comply with the provisions in paragraph (d)(3)(ii) of this section and submit the test report in the next Periodic report.

(A) *Design evaluation.* The design evaluation shall include documentation demonstrating that the control device being used achieves the required control efficiency under worst-case conditions, as determined from the emission profile described in §63.1257(b)(8)(ii). The control efficiency determined from this design evaluation shall be applied to uncontrolled emissions to estimate controlled emissions. The documentation must be conducted in accordance with the provisions in paragraph (a)(1) of this section. The design evaluation shall also include the value(s) and basis for the parameter(s) monitored under §63.1258.

(B) *Emission estimation equations.* An owner or operator using a condenser as a control device shall determine controlled emissions using exhaust gas temperature measurements and calculations for each batch emission episode within each unit operation according to the engineering methodology in paragraphs (d)(3)(i)(B)(1) through (8) of this section. Individual HAP partial pressures shall be calculated as specified in paragraph (d)(2)(i) of this section.

(1) Emissions from vapor displacement shall be calculated using Equation 11 of this subpart with T set equal to the temperature of the receiver and the HAP partial pressures determined at the temperature of the receiver.

(2) Emissions from purging shall be calculated using Equation 12 of this subpart with T set equal to the temperature of the receiver and the HAP partial pressures determined at the temperature of the receiver.

(3) Emissions from heating shall be calculated using either Equation 13 of this subpart or Equation 37 of this subpart. In Equation 13, the HAP vapor pressures shall be determined at the temperature of the receiver. In Equations 13 and 37 of this subpart, $\Delta\eta$ is equal to the number of moles of noncondensable displaced from the vessel, as calculated using Equation 15 of this subpart. In Equations 13 and 37 of this subpart, the HAP average molecular weight shall be calculated using Equation 17 with the HAP partial pressures determined at the temperature of the receiver.

$$E = \Delta\eta \times \frac{\sum_{i=1}^n P_i}{P_T - \sum_{j=1}^{10} P_j} \times MW_{HAP} \quad (Eq. 37)$$

Where:

E = mass of HAP emitted

$\Delta\eta$ = moles of noncondensable gas displaced

P_T = pressure in the receiver

P_i = partial pressure of the individual HAP at the receiver temperature

P_j = partial pressure of the individual condensable (including HAP) at the receiver temperature

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

MW_{HAP} = the average molecular weight of HAP in vapor exiting the receiver, as calculated using Equation 17 of this subpart

m = number of condensable compounds (including HAP) in the emission stream

(4)(i) Emissions from depressurization shall be calculated using Equation 38 of this subpart.

$$E = (V_{nc1} - V_{nc2}) \times \frac{\sum_{i=1}^n (P_i)}{P_T - \sum_{j=1}^m (P_j)} \times \frac{P_T}{RT} \times MW_{HAP} \quad (Eq. 38)$$

Where:

E = mass of HAP vapor emitted

V_{nc1} = initial volume of noncondensable in the vessel, corrected to the final pressure, as calculated using Equation 39 of this subpart

V_{nc2} = final volume of noncondensable in the vessel, as calculated using Equation 40 of this subpart

P_i = partial pressure of each individual HAP at the receiver temperature

P_j = partial pressure of each condensable (including HAP) at the receiver temperature

P_T = receiver pressure

T = temperature of the receiver

R = ideal gas law constant

MW_{HAP} = the average molecular weight of HAP calculated using Equation 17 of this subpart with partial pressures determined at the receiver temperature

i = identifier for a HAP compound

n = number of HAP compounds in the emission stream

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(ii) The initial and final volumes of noncondensable gas present in the vessel, adjusted to the pressure of the receiver, are calculated using Equations 39 and 40 of this subpart.

$$V_{nc1} = \frac{VP_{nc1}}{P_T} \quad (Eq. 39)$$

$$V_{nc2} = \frac{VP_{nc2}}{P_T} \quad (Eq. 40)$$

Where:

V_{nc1} = initial volume of noncondensable gas in the vessel

V_{nc2} = final volume of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1} = initial partial pressure of the noncondensable gas, as calculated using Equation 41 of this subpart

P_{nc2} = final partial pressure of the noncondensable gas, as calculated using Equation 42 of this subpart

P_T = pressure of the receiver

(iii) Initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 41 and 42 of this subpart.

$$P_{nc1} = P_1 - \sum_{j=1}^m P_j \quad (Eq. 41)$$

$$P_{nc2} = P_2 - \sum_{j=1}^m P_j \quad (Eq. 42)$$

Where:

P_{nc1} = initial partial pressure of the noncondensable gas in the vessel

P_{nc2} = final partial pressure of the noncondensable gas in the vessel

P_1 = initial vessel pressure

P_2 = final vessel pressure

P_j = partial pressure of each condensable compound (including HAP) in the vessel

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(5) Emissions from vacuum systems shall be calculated using Equation 33 of this subpart.

(6) Emissions from gas evolution shall be calculated using Equation 12 with V calculated using Equation 34 of this subpart, T set equal to the receiver temperature, and the HAP partial pressures determined at the receiver temperature. The term for time, t , in Equation 12 of this subpart is not needed for the purposes of this calculation.

(7) Emissions from air drying shall be calculated using Equation 11 of this subpart with V equal to the air flow rate and P_1 determined at the receiver temperature.

(8) Emissions from empty vessel purging shall be calculated using equation 43 of this subpart:

$$E = \frac{V}{R} \left[\left(\sum_{i=1}^n \frac{(P_i)_{T_1} (MW_i)}{T_1} \right) (-e^{-R/V}) - \left(\sum_{i=1}^n \frac{(P_i)_{T_2} (MW_i)}{T_2} \right) \left(\ln \left(\frac{\sum_{i=1}^n (P_i)_{T_2}}{\sum_{i=1}^n (P_i)_{T_1}} + 1 \right) \right) \right] \quad (Eq. 43)$$

Where:

V = volume of empty vessel

R = ideal gas law constant

T_1 = temperature of the vessel vapor space at beginning of purge

T_2 = temperature of the receiver, absolute

$(P_i)_{T_1}$ = partial pressure of the individual HAP at the beginning of the purge

$(P_i)_{T_2}$ = partial pressure of the individual HAP at the receiver temperature

MW_i = molecular weight of the individual HAP

F = flowrate of the purge gas

t = duration of the purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(ii) *Large control devices.* Except for condensers, controlled emissions for each process vent that is controlled using a large control device shall be determined by applying the control efficiency of the large control device to the estimated uncontrolled emissions. The control efficiency shall be determined by conducting a performance test on the control device as described in paragraphs (d)(3)(ii)(A) through (C) of this section, or by using the results of a previous performance test as described in paragraph (d)(4) of this section. If the control device is intended to control only hydrogen halides and halogens, the owner or operator may assume the control efficiency of organic HAP is zero percent. If the control device is intended to control only organic HAP, the owner or operator may assume the control efficiency for hydrogen halides and halogen is zero percent. Owners and operators are not required to conduct performance tests for devices described in paragraphs (a)(4) and (d)(4) of this section that are large control devices, as defined in §63.1251.

(A) The performance test shall be conducted by performing emission testing on the inlet and outlet of the control device following the test methods and procedures of §63.1257(b). Concentrations shall be calculated from the data obtained through emission testing according to the procedures in paragraph (a)(2) of this section.

(B) Performance testing shall be conducted under absolute, or hypothetical worst-case conditions, as defined in paragraphs (b)(8)(i)(A) through (B) of this section.

(C) The owner or operator may elect to conduct more than one performance test on the control device for the purpose of establishing more than one operating condition at which the control device achieves the required control efficiency.

(iii) *Initial compliance demonstration for condensers—(A) Air pollution control devices.* During periods in which a condenser functions as an air pollution control device, controlled emissions shall be calculated using the emission estimation equations described in paragraph (d)(3)(i)(B) of this section.

(B) *Process condensers.* During periods when the condenser is operating as a process condenser, the owner or operator is required to demonstrate that the process condenser is properly operated if the process condenser meets either of the criteria described in paragraphs (d)(3)(iii)(B)(1) and (2) of this section. The owner or operator must either measure the condenser exhaust gas temperature and show it is less than the boiling or bubble point of the substance(s) in the vessel, or perform a material balance around the vessel and condenser to show that at least 99 percent of the material vaporized while boiling is condensed. The initial demonstration shall be conducted for all appropriate operating scenarios and documented in the Notification of Compliance Status report described in §63.1260(f).

(1) The process condenser is not followed by an air pollution control device; or

(2) The air pollution control device following the process condenser is not a condenser or is not meeting the alternative standard of §63.1254(c).

(4) An owner or operator is not required to conduct a performance test for the following:

(i) Any control device for which a previous performance test was conducted, provided the test was conducted using the same procedures specified in §63.1257(b) over conditions typical of the appropriate worst-case, as defined in §63.1257(b)(8)(i). The results of the previous performance test shall be used to demonstrate compliance.

(e) Compliance with wastewater provisions—(1) Determining annual average concentration and annual load. To determine the annual average concentration and annual load of partially soluble and/or soluble HAP compounds in a wastewater stream, as required by §63.1256(a)(1), an owner or operator shall comply with the provisions in paragraphs (e)(1)(i) through (iii) of this section. A wastewater stream is exempt from the requirements of §63.1256(a)(2) if the owner or operator determines the annual average concentration and annual load are below all of the applicability cutoffs specified in §63.1256(a)(1)(i)(A) through (D). For annual average concentration, only initial rinses are included. Concentration measurements based on Method 305 shall be adjusted by dividing each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. Concentration measurements based on methods other than Method 305 may not be adjusted by the compound-specific Fm factor listed in Table 8 of this subpart.

(i) *Annual average concentration definition.* (A) When complying with §63.1256(a)(1)(i)(A), the annual average concentration means the total mass of partially soluble HAP compounds occurring in the wastewater stream during the calendar year divided by the total mass of the wastewater stream discharged during the same calendar year.

(B) When complying with §63.1256(a)(1)(i) (B) or (C), the annual average concentration means the total mass of partially soluble and/or soluble HAP compounds occurring in the wastewater stream during the calendar year divided by the total mass of the wastewater stream discharged during the same calendar year.

(C) When complying with §63.1256(a)(1)(i)(D), the annual average concentration means the total mass of soluble HAP compounds occurring in the wastewater stream during the calendar year divided by the total mass of the wastewater stream discharged during the same calendar year.

(ii) *Determination of annual average concentration.* An owner or operator shall determine annual average concentrations of partially soluble and/or soluble HAP compounds in accordance with the provisions specified in paragraph (e)(1)(ii)(A), (B), or (C) of this section. The owner or operator may determine annual average concentrations by process simulation. Data and other information supporting the simulation shall be reported in the Precompliance Report for approval by the Administrator. The annual average concentration shall be determined either at the POD or

downstream of the POD with adjustment for concentration changes made according to paragraph (e)(1)(ii)(D) of this section.

(A) *Test methods.* The concentration of partially soluble HAP, soluble HAP, or total HAP shall be measured using any of the methods described in paragraphs (b)(10)(i) through (iv) of this section.

(B) *Knowledge of the wastewater stream.* The concentration of partially soluble HAP, soluble HAP, or total HAP shall be calculated based on knowledge of the wastewater stream according to the procedures in paragraphs (e)(1)(ii)(B)(1) and (2) of this section. The owner or operator shall document concentrations in the Notification of Compliance Status report described in §63.1260(f).

(1) *Mass balance.* The owner or operator shall calculate the concentrations of HAP compounds in wastewater considering the total quantity of HAP discharged to the water, the amount of water at the POD, and the amounts of water and solvent lost to other mechanisms such as reactions, air emissions, or uptake in product or other processing materials. The quantities of HAP and water shall be based on batch sheets, manufacturing tickets, or FDA bills of materials. In cases where a chemical reaction occurs that generates or consumes HAP, the amount of HAP remaining after a reaction shall be based on stoichiometry assuming 100 percent theoretical consumption or yield, as applicable.

(2) *Published water solubility data.* For single components in water, owners and operators may use the water solubilities published in standard reference texts at the POD temperature to determine maximum HAP concentration.

(C) *Bench scale or pilot-scale test data.* The concentration of partially soluble HAP, soluble HAP, or total HAP shall be calculated based on bench scale or pilot-scale test data. The owner or operator shall provide sufficient information to demonstrate that the bench-scale or pilot-scale test concentration data are representative of actual HAP concentrations. The owner or operator shall also provide documentation describing the testing protocol, and the means by which sample variability and analytical variability were accounted for in the determination of HAP concentrations. Documentation of the pilot-scale or bench scale analysis shall be provided in the precompliance report.

(D) *Adjustment for concentrations determined downstream of the POD.* The owner or operator shall make corrections to the annual average concentration when the concentration is determined downstream of the POD at a location where: two or more wastewater streams have been mixed; one or more wastewater streams have been treated; or, losses to the atmosphere have occurred. The owner or operator shall make the adjustments either to the individual data points or to the final annual average concentration.

(iii) *Determination of annual load.* An owner or operator shall calculate the partially soluble and/or soluble HAP load in a wastewater stream based on the annual average concentration determined in paragraph (e)(1)(ii) (A), (B), or (C) of this section and the total volume of the wastewater stream, based on knowledge of the wastewater stream in accordance with paragraphs

(e)(1)(ii)(B) of this section. The owner or operator shall maintain records of the total liters of wastewater discharged per year as specified in §63.1259(b).

(2) *Compliance with treatment unit control provisions*—(i) *Performance tests and design evaluations-general*. To comply with the control options in §63.1256(g) (10) or (13), neither a design evaluation nor a performance test is required. For any other nonbiological treatment process, the owner or operator shall conduct either a design evaluation as specified in paragraph (e)(2)(ii) of this section, or a performance test as specified in paragraph (e)(2)(iii) of this section to demonstrate that each nonbiological treatment process used to comply with §63.1256(g) (8), (9), and/or (12) achieves the conditions specified for compliance. The owner or operator shall demonstrate by the procedures in either paragraph (e)(2) (ii) or (iii) of this section that each closed biological treatment process used to comply with §63.1256 (g)(8)(ii), (g)(9)(ii), (g)(11), or (g)(12) achieves the conditions specified for compliance. If an open biological treatment unit is used to comply with §63.1256 (g)(8)(ii), (g)(9)(ii), (g)(11), or (g)(12), the owner or operator shall comply with the performance test requirements in paragraph (e)(2)(iii) of this section.

(ii) *Design evaluation*. A design evaluation and supporting documentation that addresses the operating characteristics of the treatment process and that is based on operation at a wastewater stream flow rate and a concentration under which it would be most difficult to demonstrate compliance. For closed biological treatment processes, the percent reduction from removal/destruction in the treatment unit and control device shall be determined by a mass balance over the unit. The mass flow rate of soluble and/or partially soluble HAP compounds exiting the treatment process shall be the sum of the mass flow rate of soluble and/or partially soluble HAP compounds in the wastewater stream exiting the biological treatment process and the mass flow rate of the vented gas stream exiting the control device. The mass flow rate entering the treatment process minus the mass flow rate exiting the process determines the actual mass removal. Compounds that meet the requirements specified in paragraph (e)(2)(iii)(A)(4) of this section are not required to be included in the design evaluation; the term “performance test” in paragraph (e)(2)(iii)(A)(4) of this section shall mean “design evaluation” for the purposes of this paragraph.

(iii) *Performance tests*. Performance tests shall be conducted using test methods and procedures that meet the applicable requirements specified in paragraphs (e)(2)(iii)(A) through (G) of this section.

(A) *General*. This paragraph specifies the general procedures for performance tests that are conducted to demonstrate compliance of a treatment process with the control requirements specified in §63.1256(g).

(1) *Representative process unit operating conditions*. Compliance shall be demonstrated for representative operating conditions. Operations during periods of malfunction and periods of nonoperation shall not constitute representative conditions. The owner or operator shall record the process information that is necessary to document operating conditions during the test.

(2) *Representative treatment process operating conditions*. Performance tests shall be conducted when the treatment process is operating at a representative inlet flow rate and concentration. If

the treatment process will be operating at several different sets of representative operating conditions, the owner or operator shall comply with paragraphs (e)(2)(iii)(A)(2)(i) and (ii) of this section. The owner or operator shall record information that is necessary to document treatment process or control device operating conditions during the test.

(i) *Range of operating conditions.* If the treatment process will be operated at several different sets of representative operating conditions, performance testing over the entire range is not required. In such cases, the performance test results shall be supplemented with modeling and/or engineering assessments to demonstrate performance over the operating range.

(ii) *Consideration of residence time.* If concentration and/or flow rate to the treatment process are not relatively constant (i.e., comparison of inlet and outlet data will not be representative of performance), the owner or operator shall consider residence time, when determining concentration and flow rate.

(3) *Testing equipment.* All testing equipment shall be prepared and installed as specified in the applicable test methods, or as approved by the Administrator.

(4) *Compounds not required to be considered in performance tests.* Compounds that meet the requirements specified in (e)(2)(iii)(A)(4)(i), (ii), or (iii) of this section are not required to be included in the performance test. Concentration measurements based on Method 305 shall be adjusted by dividing each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. Concentration measurements based on methods other than Method 305 shall not be adjusted by the compound-specific Fm factor listed in Table 8 of this subpart.

(i) Compounds not used or produced by the PMPU; or

(ii) Compounds with concentrations at the POD that are below 1 ppmw; or

(iii) Compounds with concentrations at the POD that are below the lower detection limit where the lower detection limit is greater than 1 ppmw. The method shall be an analytical method for wastewater which has the compound of interest as a target analyte.

(5) *Treatment using a series of treatment processes.* In all cases where the wastewater provisions in this subpart allow or require the use of a treatment process to comply with emissions limitations, the owner or operator may use multiple treatment processes. The owner or operator complying with the requirements of §63.1256(g)(7)(i), when wastewater is conveyed by hard-piping, shall comply with either paragraph (e)(2)(iii)(A)(5)(i) or (ii) of this section. The owner or operator complying with the requirements of §63.1256(g)(7)(ii) shall comply with the requirements of paragraph (e)(2)(iii)(A)(5)(ii) of this section.

(i) The owner or operator shall conduct the performance test across each series of treatment processes. For each series of treatment processes, inlet concentration and flow rate shall be measured either where the wastewater enters the first treatment process in a series of treatment processes, or prior to the first treatment process as specified in paragraph (e)(2)(iii)(A)(6) of this section. For each series of treatment processes, outlet concentration and flow rate shall be

measured where the wastewater exits the last treatment process in the series of treatment processes, except when the last treatment process is an open or a closed aerobic biological treatment process demonstrating compliance by using the procedures in paragraphs (e)(2)(iii)(E) or (F) of this section. When the last treatment process is either an open or a closed aerobic biological treatment process demonstrating compliance by using the procedures in paragraphs (e)(2)(iii)(E) or (F) of this section, inlet and outlet concentrations and flow rates shall be measured at the inlet and outlet to the series of treatment processes prior to the biological treatment process and at the inlet to the biological treatment process, except as provided in paragraph (e)(2)(iii)(A)(6)(ii) of this section. The mass flow rate destroyed in the biological treatment process for which compliance is demonstrated using paragraph (e)(2)(iii)(E) or (F) of this section shall be added to the mass flow rate removed or destroyed in the series of treatment units before the biological treatment unit. This sum shall be used to calculate the overall control efficiency.

(ii) The owner or operator shall conduct the performance test across each treatment process in the series of treatment processes. The mass flow rate removed or destroyed by each treatment process shall be added together and the overall control efficiency calculated to determine whether compliance has been demonstrated using paragraphs (e)(2)(iii)(C), (D), (E), (F), or (G) of this section, as applicable. If a biological treatment process is one of the treatment processes in the series of treatment processes, the inlet to the biological treatment process shall be the point at which the wastewater enters the biological treatment process, or the inlet to the equalization tank if all the criteria of paragraph (e)(2)(iii)(A)(6)(ii) of this section are met.

(6) The owner or operator determining the inlet for purposes of demonstrating compliance with paragraph (e)(2)(iii)(E), or (F) of this section may elect to comply with paragraph (e)(2)(iii)(A)(6)(i) or (ii) of this section.

(i) When wastewater is conveyed exclusively by hard-piping from the point of determination to a treatment process that is either the only treatment process or the first in a series of treatment processes (i.e., no treatment processes or other waste management units are used upstream of this treatment process to store, handle, or convey the wastewater), the inlet to the treatment process shall be at any location from the point of determination to where the wastewater stream enters the treatment process. When samples are taken upstream of the treatment process and before wastewater streams have converged, the owner or operator shall ensure that the mass flow rate of all affected wastewater is accounted for when using §63.1256(g)(8)(ii), (g)(9)(ii) or (g)(12) of this subpart to comply and that the mass flow rate of all wastewater, not just affected wastewater, is accounted for when using §63.1256(g)(11) to comply, except as provided in paragraph (e)(2)(iii)(A)(4) of this section.

(ii) The owner or operator may consider the inlet to the equalization tank as the inlet to the biological treatment process if the wastewater is conveyed by hard-piping from either the last previous treatment process or the point of determination to the equalization tank; and the wastewater is conveyed from the equalization tank exclusively by hard-piping to the biological treatment process and no treatment processes or other waste management units are used to store, handle, or convey the wastewater between the equalization tank and the biological treatment process; and the equalization tank is equipped with a fixed roof and a closed-vent system that

routes emissions to a control device that meets the requirements of §63.1256(b)(1)(i) through (iv) and §63.1256(b)(2)(i). The outlet from the series of treatment processes prior to the biological treatment process is the point at which the wastewater exits the last treatment process in the series prior to the equalization tank, if the equalization tank and biological treatment process are part of a series of treatment processes. The owner or operator shall ensure that the mass flow rate of all affected wastewater is accounted for when using §63.1256(g)(9)(ii) or (12) to comply and that the mass flow rate of all wastewater, not just affected wastewater is accounted for when using §63.1256(g)(11) to comply, except as provided in paragraph (e)(2)(iii)(A)(4) of this section.

(B) *Noncombustion treatment process—concentration limits.* This paragraph applies to performance tests that are conducted to demonstrate compliance of a noncombustion treatment process with the ppmw wastewater stream concentration limits at the outlet of the treatment process. This compliance option is specified in §63.1256(g)(8)(i) and (9)(i). Wastewater samples shall be collected using sampling procedures which minimize loss of organic compounds during sample collection and analysis and maintain sample integrity per paragraph (b)(10)(vi) of this section. Samples shall be collected and analyzed using the procedures specified in paragraphs (b)(10)(i) through (vi) of this section. Samples may be grab samples or composite samples. Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements based on methods other than Method 305 may be adjusted by multiplying each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. (For affected wastewater streams that contains both partially soluble and soluble HAP compounds, compliance is demonstrated only if the sum of the concentrations of partially soluble HAP compounds is less than 50 ppmw, and the sum of the concentrations of soluble HAP compounds is less than 520 ppmw.)

(C) *Noncombustion, nonbiological treatment process: percent mass removal/destruction option.* This paragraph applies to performance tests that are conducted to demonstrate compliance of a noncombustion, nonbiological treatment process with the percent mass removal limits specified in §63.1256(g)(8)(ii) and (9)(ii) for partially soluble and soluble HAP compounds, respectively. The owner or operator shall comply with the requirements specified in paragraphs (e)(2)(iii)(C)(1) through (5) of this section.

(1) *Concentration.* The concentration of partially soluble and/or soluble HAP compounds entering and exiting the treatment process shall be determined as provided in this paragraph. Wastewater samples shall be collected using sampling procedures which minimize loss of organic compounds during sample collection and analysis and maintain sample integrity per paragraph (b)(10)(vi) of this section. The method shall be an analytical method for wastewater which has the compound of interest as a target analyte. Samples may be grab samples or composite samples. Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements based on Method 305 shall be adjusted by dividing each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. Concentration measurements based on methods other than Method 305 shall not be adjusted by the compound-specific Fm factor listed in Table 8 of this subpart.

(2) *Flow rate.* The flow rate of the entering and exiting wastewater streams shall be determined using inlet and outlet flow meters, respectively. Where the outlet flow is not greater than the inlet flow, a single flow meter may be used, and may be used at either the inlet or outlet. Flow rate measurements shall be taken at the same time as the concentration measurements.

(3) *Calculation of mass flow rate—for noncombustion, nonbiological treatment processes.* The mass flow rates of partially soluble and/or soluble HAP compounds entering and exiting the treatment process are calculated using Equations 44 and 45 of this subpart.

$$QMW_a = \frac{\rho}{p * 10^6} \left(\sum_{k=1}^p (Q_{a,k} * C_{T,a,k}) \right) \quad (Eq. 44)$$

$$QMW_b = \frac{\rho}{p * 10^6} \left(\sum_{k=1}^p (Q_{b,k} * C_{T,b,k}) \right) \quad (Eq. 45)$$

Where:

QMW_a , QMW_b = mass flow rate of partially soluble or soluble HAP compounds, average of all runs, in wastewater entering (QMW_a) or exiting (QMW_b) the treatment process, kg/hr

ρ = density of the wastewater, kg/m³

$Q_{a,k}$, $Q_{b,k}$ = volumetric flow rate of wastewater entering ($Q_{a,k}$) or exiting ($Q_{b,k}$) the treatment process during each run k , m³/hr

$C_{T,a,k}$, $C_{T,b,k}$ = total concentration of partially soluble or soluble HAP compounds in wastewater entering ($C_{T,a,k}$) or exiting ($C_{T,b,k}$) the treatment process during each run k , ppmw

p = number of runs

k = identifier for a run

106 = conversion factor, mg/kg

(4) *Percent removal calculation for mass flow rate.* The percent mass removal across the treatment process shall be calculated as follows:

$$E = \frac{QMW_a - QMW_b}{QMW_a} \times 100 \quad (Eq. 46)$$

Where:

E = removal or destruction efficiency of the treatment process, percent

QMW_a , QMW_b = mass flow rate of partially soluble or soluble HAP compounds in wastewater entering (QMW_a) and exiting (QMW_b) the treatment process, kg/hr (as calculated using Equations 44 and 45 of this subpart)

(5) *Compare mass removal efficiency to required efficiency.* Compare the mass removal efficiency (calculated in Equation 46 of this subpart) to the required efficiency as specified in §63.1256(g)(8)(ii) or (9)(ii). If complying with §63.1256(g)(8)(ii), compliance is demonstrated if the mass removal efficiency is 99 percent or greater. If complying with §63.1256(g)(9)(ii), compliance is demonstrated if the mass removal efficiency is 90 percent or greater.

(D) *Combustion treatment processes: percent mass removal/destruction option.* This paragraph applies to performance tests that are conducted to demonstrate compliance of a combustion treatment process with the percent mass destruction limits specified in §63.1256(g)(8)(ii) for partially soluble HAP compounds, and/or §63.1256(g)(9)(ii) for soluble HAP compounds. The owner or operator shall comply with the requirements specified in paragraphs (e)(2)(iii)(D)(I) through (8) of this section.

(1) *Concentration in wastewater stream entering the combustion treatment process.* The concentration of partially soluble and/or soluble HAP compounds entering the treatment process shall be determined as provided in this paragraph. Wastewater samples shall be collected using sampling procedures which minimize loss of organic compounds during sample collection and analysis and maintain sample integrity per paragraph (b)(10)(vi) of this section. The method shall be an analytical method for wastewater which has the compound of interest as a target analyte. Samples may be grab samples or composite samples. Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements based on Method 305 of appendix A of this part shall be adjusted by dividing each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. Concentration measurements based on methods other than Method 305 shall not be adjusted by the compound-specific Fm factor listed in Table 8 of this subpart.

(2) *Flow rate of wastewater entering the combustion treatment process.* The flow rate of the wastewater stream entering the combustion treatment process shall be determined using an inlet flow meter. Flow rate measurements shall be taken at the same time as the concentration measurements.

(3) *Calculation of mass flow rate in wastewater stream entering combustion treatment processes.* The mass flow rate of partially soluble and/or soluble HAP compounds entering the treatment process is calculated as follows:

$$QMW_a = \frac{\rho}{P * 10^6} \left(\sum_{k=1}^p (Q_{a,k} * C_{T,a,k}) \right) \quad (Eq. 47)$$

Where:

QMW_a = mass flow rate of partially soluble or soluble HAP compounds entering the combustion unit, kg/hr

ρ = density of the wastewater stream, kg/m³

$Q_{a, k}$ = volumetric flow rate of wastewater entering the combustion unit during run k, m³/hr

$C_{T, a, k}$ = total concentration of partially soluble or soluble HAP compounds in the wastewater stream entering the combustion unit during run k, ppmw

k = identifier for a run

p = number of runs

(4) *Concentration in vented gas stream exiting the combustion treatment process.* The concentration of partially soluble and/or soluble HAP compounds (or TOC) exiting the combustion treatment process in any vented gas stream shall be determined as provided in this paragraph. Samples may be grab samples or composite samples. Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(5) *Volumetric flow rate of vented gas stream exiting the combustion treatment process.* The volumetric flow rate of the vented gas stream exiting the combustion treatment process shall be determined using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate. Volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(6) *Calculation of mass flow rate of vented gas stream exiting combustion treatment processes.* The mass flow rate of partially soluble and/or soluble HAP compounds in a vented gas stream exiting the combustion treatment process shall be calculated as follows:

$$QMG_b = K_1 * \left(\sum_{i=1}^n (CG_{b, i} * MW_i) \right) * QG_b \quad (Eq. 48)$$

Where:

QMG_b = mass rate of TOC (minus methane and ethane) or total partially soluble and/or soluble HAP, in vented gas stream, exiting (QMG_b) the combustion device, dry basis, kg/hr

$CG_{b, i}$ = concentration of TOC (minus methane and ethane) or total partially soluble and/or soluble HAP, in vented gas stream, exiting ($CG_{b, i}$) the combustion device, dry basis, ppmv

MW_i = molecular weight of a component, kilogram/kilogram-mole

QG_b = flow rate of gas stream exiting (QG_b) the combustion device, dry standard cubic meters per hour

K_2 = constant, 41.57×10^{-9} (parts per million)⁻¹ (gram-mole per standard cubic meter) (kilogram/gram), where standard temperature (gram-mole per standard cubic meter) is 20 °C

i = identifier for a compound

n = number of components in the sample

(7) *Destruction efficiency calculation.* The destruction efficiency of the combustion unit for partially soluble and/or soluble HAP compounds shall be calculated as follows:

$$E = \frac{QMW_a - QMG_b}{QMW_a} \times 100 \quad (Eq. 49)$$

Where:

E = destruction efficiency of partially soluble or soluble HAP compounds for the combustion unit, percent

QMW_{2a} = mass flow rate of partially soluble or soluble HAP compounds entering the combustion unit, kg/hr

QMG_b = mass flow rate of TOC (minus methane and ethane) or partially soluble and/or soluble HAP compounds in vented gas stream exiting the combustion treatment process, kg/hr

(8) *Compare mass destruction efficiency to required efficiency.* Compare the mass destruction efficiency (calculated in Equation 49 of this subpart) to the required efficiency as specified in §63.1256(g)(8)(ii) or (g)(9)(ii). If complying with §63.1256(g)(8)(ii), compliance is demonstrated if the mass destruction efficiency is 99 percent or greater. If complying with §63.1256(g)(9)(ii), compliance is demonstrated if the mass destruction efficiency is 90 percent or greater.

(E) *Open or closed aerobic biological treatment processes: 95-percent mass destruction option.* This paragraph applies to performance tests that are conducted for open or closed aerobic biological treatment processes to demonstrate compliance with the 95-percent mass destruction provisions in §63.1256(g)(11) for partially soluble and/or soluble HAP compounds.

(1) *Concentration in wastewater stream.* The concentration of partially soluble and/or soluble HAP as provided in this paragraph. Concentration measurements to determine E shall be taken as provided in paragraph (e)(2)(iii)(A)(5) of this section for a series of treatment processes. Wastewater samples shall be collected using sampling procedures which minimize loss of organic compounds during sample collection and analysis and maintain sample integrity per paragraph (b)(10)(vi) of this section. The method shall be an analytical method for wastewater which has the compound of interest as a target analyte. Samples may be grab samples or

composite samples. Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements based on Method 305 shall be adjusted by dividing each concentration by the compound-specific Fm factor listed in Table 8 of this subpart. Concentration measurements based on methods other than Method 305 shall not be adjusted by the compound-specific Fm factor listed in Table 8 of this subpart.

(2) *Flow rate.* Flow rate measurements to determine E shall be taken as provided in paragraph (e)(2)(iii)(A)(5) of this section for a series of treatment processes. Flow rate shall be determined using inlet and outlet flow measurement devices. Where the outlet flow is not greater than the inlet flow, a single flow measurement device may be used, and may be used at either the inlet or outlet. Flow rate measurements shall be taken at the same time as the concentration measurements.

(3) *Destruction efficiency.* The owner or operator shall comply with the provisions in either paragraph (e)(2)(iii)(E)(3)(i) or (ii) of this section. Compliance is demonstrated if the destruction efficiency, E, is equal to or greater than 95 percent.

(i) If the performance test is performed across the open or closed biological treatment system only, compliance is demonstrated if E is equal to F_{bio} , where E is the destruction efficiency of partially soluble and/or soluble HAP compounds and F_{bio} is the site-specific fraction of partially soluble and/or soluble HAP compounds biodegraded. F_{bio} shall be determined as specified in paragraph (e)(2)(iii)(E)(4) of this section and appendix C of subpart G of this part.

(ii) If compliance is being demonstrated in accordance with paragraphs (e)(2)(iii)(A)(5)(i) or (ii) of this section, the removal efficiency shall be calculated using Equation 50 of this subpart. When complying with paragraph (e)(2)(iii)(A)(5)(i) of this section, the series of nonbiological treatment processes comprise one treatment process segment. When complying with paragraph (e)(2)(iii)(A)(5)(ii) of this section, each nonbiological treatment process is a treatment process segment.

$$E = \frac{\text{Nonbiotreatment HAP load removal} + \text{Biotreatment HAP load removal}}{\text{Total influent HAP load}} = \frac{\left(\sum_{i=1}^n (QMW_{a,i} - QMW_{b,i}) \right) + QMW_{bio} * F_{bio}}{QMW_{in}} \quad (Eq. 50)$$

Where:

$QMW_{a,i}$ = the soluble and/or partially soluble HAP load entering a treatment process segment

$QMW_{b,i}$ = the soluble and/or partially soluble HAP load exiting a treatment process segment

n = the number of treatment process segments

i = identifier for a treatment process element

QMW_{bio} = the inlet load of soluble and/or partially soluble HAP to the biological treatment process. The inlet is defined in accordance with paragraph (e)(2)(iii)(A)(6) of this section. If complying with paragraph (e)(2)(iii)(A)(6)(ii) of this section, QMW_{bio} is equal to $QMW_{b, n}$.

F_{bio} = site-specific fraction of soluble and/or partially soluble HAP compounds biodegraded. F_{bio} shall be determined as specified in paragraph (e)(2)(iii)(E)(4) of this section and Appendix C of subpart G of this part.

QMW_{all} = the total soluble and/or partially soluble HAP load to be treated.

(4) *Site-specific fraction biodegraded* (F_{bio}). The procedures used to determine the compound-specific kinetic parameters for use in calculating F_{bio} differ for the compounds listed in Tables 2 and 3 of this subpart. An owner or operator shall calculate F_{bio} as specified in either paragraph (e)(2)(iii)(E)(4)(i) or (ii) of this section.

(i) For biological treatment processes that do not meet the definition for enhanced biological treatment in §63.1251, the owner or operator shall determine the F_{bio} for the compounds in Tables 2 and 3 of this subpart using any of the procedures in appendix C to part 63, except procedure 3 (inlet and outlet concentration measurements). (The symbol “ F_{bio} ” represents the site-specific fraction of an individual partially soluble or soluble HAP compound that is biodegraded.)

(ii) If the biological treatment process meets the definition of “enhanced biological treatment process” in §63.1251, the owner or operator shall determine F_{bio} for the compounds in Table 2 of this subpart using any of the procedures specified in appendix C to part 63. The owner or operator shall calculate F_{bio} for the compounds in Table 3 of this subpart using the defaults for first order biodegradation rate constants (K_1) in Table 9 of this subpart and follow the procedure explained in Form III of appendix C, 40 CFR part 63, or any of the procedures specified in appendix C of 40 CFR part 63.

(F) *Open or closed aerobic biological treatment processes: percent removal for partially soluble or soluble HAP compounds.* This paragraph applies to the use of performance tests that are conducted for open or closed aerobic biological treatment processes to demonstrate compliance with the percent removal provisions for either partially soluble HAP compounds in §63.1256(g)(8)(ii) or soluble HAP compounds in §63.1256(g)(9)(ii) or (g)(12). The owner or operator shall comply with the provisions in paragraph (e)(2)(iii)(E) of this section, except that compliance with §63.1256(g)(8)(ii) shall be demonstrated when E is equal to or greater than 99 percent, compliance with §63.1256(g)(9)(ii) shall be demonstrated when E is equal to or greater than 90 percent, and compliance with §63.1256(g)(12) shall be demonstrated when E is equal to or greater than 99 percent.

(G) *Closed biological treatment processes: percent mass removal option.* This paragraph applies to the use of performance tests that are conducted for closed biological treatment processes to demonstrate compliance with the percent removal provisions in §§63.1256(g)(8)(ii), (g)(9)(ii), (g)(11), or (g)(12). The owner or operator shall comply with the requirements specified in paragraphs (e)(2)(iii)(G) (1) through (4) of this section.

(1) Comply with the procedures specified in paragraphs (e)(2)(iii)(C) (1) through (3) of this section to determine characteristics of the wastewater entering the biological treatment unit, except that the term “partially soluble and/or soluble HAP” shall mean “soluble HAP” for the purposes of this section if the owner or operator is complying with §63.1256(g)(9)(ii) or (g)(12), and it shall mean “partially soluble HAP” if the owner or operator is complying with §63.1256(g)(8)(ii).

(2) Comply with the procedures specified in paragraphs (e)(2)(iii)(D) (4) through (6) of this section to determine the characteristics of gas vent streams exiting a control device, with the differences noted in paragraphs (e)(2)(iii)(G)(3) (i) and (ii) of this section.

(i) The term “partially soluble and/or soluble HAP” shall mean “soluble HAP” for the purposes of this section if the owner or operator is complying with §63.1256(g)(9)(ii) or (g)(12), and it shall mean “partially soluble HAP” if the owner or operator is complying with §63.1256(g)(8)(ii).

(ii) The term “combustion treatment process” shall mean “control device” for the purposes of this section.

(3) *Percent removal/destruction calculation.* The percent removal and destruction across the treatment unit and any control device(s) shall be calculated using Equation 51 of this subpart:

$$E = \frac{(QMW_a - (QMW_b + QMG_b))}{QMW_a} \quad (Eq. 51)$$

Where:

E = removal and destruction efficiency of the treatment unit and control device(s), percent

QMW_a, QMW_b = mass flow rate of partially soluble and/or soluble HAP compounds in wastewater entering (QMW_a) and exiting (QMW_b) the treatment process, kilograms per hour (as calculated using Equations 44 and 45)

QMG_b = mass flow rate of partially soluble and/or soluble HAP compounds in vented gas stream exiting the control device, kg/hr

(4) *Compare mass removal/destruction efficiency to required efficiency.* Compare the mass removal/destruction efficiency (calculated using Equation 51 of this subpart) to the required efficiency as specified in §63.1256(g)(8)(ii), (g)(9)(ii), (g)(11), or (g)(12). If complying with §63.1256(g)(8)(ii), compliance is demonstrated if the mass removal/destruction is 99 percent or greater. If complying with §63.1256(g)(9)(ii), compliance is demonstrated if the mass removal/destruction efficiency is 90 percent or greater. If complying with §63.1256(g)(11), compliance is demonstrated if the mass removal/destruction efficiency is 95 percent or greater. If complying with §63.1256(g)(12), compliance is demonstrated if the mass removal/destruction efficiency is 99 percent or greater.

(3) *Compliance with control device provisions.* Except as provided in paragraph (e)(3)(iv) of this section, an owner or operator shall demonstrate that each control device or combination of control devices achieves the appropriate conditions specified in §63.1256(h)(2) by using one or more of the methods specified in paragraphs (e)(3)(i), (ii), or (iii) of this section.

(i) *Performance test for control devices other than flares.* This paragraph applies to performance tests that are conducted to demonstrate compliance of a control device with the efficiency limits specified in §63.1256(h)(2). If complying with the 95-percent reduction efficiency requirement, comply with the requirements specified in paragraphs (e)(3)(i) (A) through (J) of this section. If complying with the 20 ppm by volume requirement, comply with the requirements specified in paragraphs (e)(3)(i) (A) through (G) and (e)(3)(i)(J) of this section.

(A) *General.* The owner or operator shall comply with the general performance test provisions in paragraphs (e)(2)(iii)(A) (1) through (4) of this section, except that the term “treatment unit” shall mean “control device” for the purposes of this section.

(B) *Sampling sites.* Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate. For determination of compliance with the 95 percent reduction requirement, sampling sites shall be located at the inlet and the outlet of the control device. For determination of compliance with the 20 ppmv limit, the sampling site shall be located at the outlet of the control device.

(C) *Concentration in gas stream entering or exiting the control device.* The concentration of total organic HAP or TOC in a gas stream shall be determined as provided in this paragraph. Samples may be grab samples or composite samples (i.e., integrated samples). Samples shall be taken at approximately equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of three runs. Concentration measurements shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(D) *Volumetric flow rate of gas stream entering or exiting the control device.* The volumetric flow rate of the gas stream shall be determined using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate. Volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(E) *Calculation of TOC concentration.* The owner or operator shall compute TOC in accordance with the procedures in paragraph (a)(2) of this section.

(F) *Calculation of total organic HAP concentration.* The owner or operator determining compliance based on total organic HAP concentration shall compute the total organic HAP concentration in accordance with the provisions in paragraph (a)(2) of this section.

(G) *Requirements for combustion control devices.* If the control device is a combustion device, the owner or operator shall correct TOC and organic HAP concentrations to 3 percent oxygen in accordance with the provisions in paragraph (a)(3) of this section, and demonstrate initial

compliance with the requirements for halogenated streams in accordance with paragraph (a)(6) of this section.

(H) *Mass rate calculation.* The mass rate of either TOC (minus methane and ethane) or total organic HAP for each sample run shall be calculated using the following equations. Where the mass rate of TOC is being calculated, all organic compounds (minus methane and ethane) measured by methods specified in paragraph (e)(3)(i)(C) of this section are summed using Equations 52 and 53 of this subpart. Where the mass rate of total organic HAP is being calculated, only soluble and partially soluble HAP compounds shall be summed using Equations 52 and 53.

$$QMG_a = K_2 * \left(\sum_{i=1}^n (CG_{a,i}) * (MW_i) \right) * QG_a \quad (Eq. 52)$$

$$QMG_b = K_2 * \left(\sum_{i=1}^n (CG_{b,i}) * (MW_i) \right) * QG_b \quad (Eq. 53)$$

Where:

$CG_{a,i}$, $CG_{b,i}$ = concentration of TOC or total organic HAP, in vented gas stream, entering ($CG_{a,i}$) and exiting ($CG_{b,i}$) the control device, dry basis, ppmv

QMG_a , QMG_b = mass rate of TOC or total organic HAP, in vented gas stream, entering (QMG_a) and exiting (QMG_b) the control device, dry basis, kg/hr

M_{wi} = molecular weight of a component, kilogram/kilogram-mole

QG_a , QG_b = flow rate of gas stream entering (QG_a) and exiting (QG_b) the control device, dry standard cubic meters per hour

K_2 = constant, 41.57×10^{-9} (parts per million)⁻¹ (gram-mole per standard cubic meter) (kilogram/gram), where standard temperature (gram-mole per standard cubic meter) is 20 °C

i = identifier for a compound

n = number of components in the sample

(I) *Percent reduction calculation.* The percent reduction in TOC or total organic HAP for each sample run shall be calculated using Equation 54 of this subpart:

$$E = \frac{QMG_a - QMG_b}{QMG_a} (100\%) \quad (Eq. 54)$$

Where:

E = destruction efficiency of control device, percent

QMG_a, QMG_b = mass rate of TOC or total organic HAP, in vented gas stream entering and exiting (QMG_b) the control device, dry basis, kilograms per hour

(J) *Compare mass destruction efficiency to required efficiency.* If complying with the 95-percent reduction efficiency requirement, compliance is demonstrated if the mass destruction efficiency (calculated in Equation 51 of this subpart) is 95 percent or greater. If complying with the 20 ppmv limit, compliance is demonstrated if the outlet TOC concentration is 20 ppmv, or less.

(ii) *Design evaluation.* A design evaluation conducted in accordance with the provisions in paragraph (a)(1) of this section. Compounds that meet the requirements specified in paragraph (e)(2)(iii)(A)(4) of this section are not required to be included in the design evaluation.

(iii) *Compliance demonstration for flares.* When a flare is used to comply with §63.1256(h), the owner or operator shall comply with the flare provisions in §63.11(b). An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration when a flare is used.

(iv) *Exemptions from compliance demonstrations.* An owner or operator using any control device specified in paragraph (a)(4) of this section is exempt from the requirements in paragraphs (e)(3)(i) through (e)(3)(iii) of this section and from the requirements in §63.6(f).

(f) *Pollution prevention alternative standard.* The owner or operator shall demonstrate compliance with §63.1252(e)(2) using the procedures described in paragraph (f)(1) and (f)(3) of this section. The owner or operator shall demonstrate compliance with §63.1252(e)(3) using the procedures described in paragraphs (f)(2) and (f)(3) of this section.

(1) Compliance is demonstrated when the annual kg/kg factor, calculated according to the procedure in paragraphs (f)(1)(i) and (iii) of this section, is reduced by at least 75 percent as calculated according to the procedure in paragraph (f)(1)(i) and (ii) of this section.

(i) The production-indexed HAP consumption factors shall be calculated by dividing annual consumption of total HAP by the annual production rate, per process. The production-indexed total VOC consumption factor shall be calculated by dividing annual consumption of total VOC by the annual production rate, per process.

(ii) The baseline factor is calculated from yearly production and consumption data for the first 3-year period in which the PMPU was operational, beginning no earlier than the 1987 calendar year, or for a minimum period of 12 months from startup of the process until the present in which the PMPU was operational and data are available, beginning no earlier than the 1987 calendar year.

(iii) The annual factor is calculated on the following bases:

(A) For continuous processes, the annual factor shall be calculated every 30 days for the 12-month period preceding the 30th day (30-day rolling average).

(B) For batch processes, the annual factor shall be calculated either every 10 batches for the 12-month period preceding the 10th batch (10-batch rolling average) or a maximum of once per month, if the number of batches is greater than 10 batches per month. The annual factor shall be calculated every 5 batches if the number of batches is less than 10 for the 12-month period preceding the 10th batch and shall be calculated every year if the number of batches is less than 5 for the 12-month period preceding the 5th batch.

(2) Compliance is demonstrated when the requirements of paragraphs (f)(2)(i) through (iv) of this section are met.

(i) The annual kg/kg factor, calculated according to the procedure in paragraphs (f)(1)(i) and (f)(1)(iii) of this section, is reduced to a value equal to or less than 50 percent of the baseline factor calculated according to the procedure in paragraphs (f)(1)(i) and (ii) of this section.

(ii) The yearly reductions associated with add-on controls that meet the criteria of §§63.1252(h)(3)(ii)(A) through (D) must be equal to or greater than the amounts calculated in paragraphs (f)(2)(ii)(A) and (B) of this section:

(A) The mass of HAP calculated using Equation 55 of this subpart:

$$M = [\text{kg/kg}]_b (0.75 - P_R) (M_{\text{prod}}) \quad (\text{Eq. 55})$$

Where:

$[\text{kg/kg}]_b$ = the baseline production-indexed HAP consumption factor, in kg/kg

M_{prod} = the annual production rate, in kg/yr

M = the annual reduction required by add-on controls, in kg/yr

P_R = the fractional reduction in the annual kg/kg factor achieved using pollution prevention
where P_R is ≥ 0.5

(B) The mass of VOC calculated using Equation 56 of this subpart:

$$\text{VOC}_{\text{reduced}} = (\text{VF}_{\text{base}} - \text{VF}_p - \text{VF}_{\text{annual}}) \times M_{\text{prod}} \quad (\text{Eq. 56})$$

Where:

$\text{VOC}_{\text{reduced}}$ = required VOC emission reduction from add-on controls, kg/yr

VF_{base} = baseline VOC factor, kg VOC emitted/kg production

VF_p = reduction in VOC factor achieved by pollution prevention, kg VOC emitted/kg production

$\text{VF}_{\text{annual}}$ = target annual VOC factor, kg VOC emitted/kg production

M_{prod} = production rate, kg/yr

(iii) Demonstration that the criteria in §63.1252(e)(3)(ii)(A) through (D) are met shall be accomplished through a description of the control device and of the material streams entering and exiting the control device.

(iv) The annual reduction achieved by the add-on control shall be quantified using the methods described in §63.1257(d).

(3) Each owner or operator of a PMPU complying with the P2 standard shall prepare a P2 demonstration summary that shall contain, at a minimum, the following information:

(i) Descriptions of the methodologies and forms used to measure and record daily consumption of HAP compounds reduced as part of the P2 standard.

(ii) Descriptions of the methodologies and forms used to measure and record daily production of products which are included in the P2 standard.

(iii) Supporting documentation for the descriptions provided in paragraphs (f)(3)(i) and (ii) including, but not limited to, operator log sheets and copies of daily, monthly, and annual inventories of materials and products.

(g) *Compliance with storage tank provisions by using emissions averaging.* An owner or operator with two or more affected storage tanks may demonstrate compliance with §63.1253, as applicable, by fulfilling the requirements of paragraphs (g)(1) through (4) of this section.

(1) The owner or operator shall develop and submit for approval an Implementation Plan containing all the information required in §63.1259(e) 6 months prior to the compliance date of the standard. The Administrator shall have 90 days to approve or disapprove the emissions averaging plan after which time the plan shall be considered approved.

(2) The annual mass rate of total organic HAP (E^{Ti} , E^{To}) shall be calculated for each storage tank included in the emissions average using the procedures specified in paragraph (c)(1), (2), or (3) of this section.

(3) Equations 57 and 58 of this subpart shall be used to calculate total HAP emissions for those tanks subject to §63.1253(b) or (c):

$$E_{\text{Ti}} = \sum_{j=1}^n E_{ij} \quad (\text{Eq. 57})$$

$$E_{\text{To}} = \sum_{j=1}^n E_{oj} \quad (\text{Eq. 58})$$

Where:

E_{ij} = yearly mass rate of total HAP at the inlet of the control device for tank j

E_{oj} = yearly mass rate of total HAP at the outlet of the control device for tank j

ET_i = total yearly uncontrolled HAP emissions

E_{To} = total yearly actual HAP emissions

n = number of tanks included in the emissions average

(4) The overall percent reduction efficiency shall be calculated as follows:

$$R = \frac{E_{Ti} - D E_{To}}{E_{Ti}} 100\% \quad (\text{Eq. 59})$$

Where:

R = overall percent reduction efficiency

D = discount factor = 1.1 for all controlled storage tanks

(h) *Compliance with process vent provisions by using emissions averaging.* An owner or operator with two or more affected processes complying with §63.1254 by using emissions averaging shall demonstrate compliance with paragraphs (h)(1), (2) and (3) of this section.

(1) The owner or operator shall develop and submit for approval an Implementation Plan at least 6 months prior to the compliance date of the standard containing all the information required in §63.1259(e). The Administrator shall have 90 days to approve or disapprove the emissions averaging plan. The plan shall be considered approved if the Administrator either approves the plan in writing, or fails to disapprove the plan in writing. The 90-day period shall begin when the Administrator receives the request. If the request is denied, the owner or operator must still be in compliance with the standard by the compliance date.

(2) Owners or operators shall calculate uncontrolled and controlled emissions of HAP by using the methods specified in paragraph (d)(2) and (3) of this section for each process included in the emissions average.

(3) Equations 60 and 61 of this subpart shall be used to calculate total HAP emissions:

$$E_{TV} = \sum_{i=1}^n E_{Ti} \quad (\text{Eq. 60})$$

$$E_{TC} = \sum_{i=1}^n E_{Ci} \quad (\text{Eq. 61})$$

Where:

E_{ui} = yearly uncontrolled emissions from process i.

E_{ci} = yearly actual emissions for process i.

E_{TU} = total yearly uncontrolled emissions.

E_{TC} = total yearly actual emissions.

n = number of processes included in the emissions average.

(4) The overall percent reduction efficiency shall be calculated using Equation 62 of this subpart:

$$R = \frac{E_{TU} - D E_{TC}}{E_{TU}} (100\%) \quad (Eq. 62)$$

Where:

R = overall percent reduction efficiency

D = discount factor = 1.1 for all controlled emission points

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52609, Aug. 29, 2000; 66 FR 40134, Aug. 2, 2001; 76 FR 22600, Apr. 21, 2011]

§63.1258 Monitoring Requirements.

(a) The owner or operator of any existing, new, or reconstructed affected source shall provide evidence of continued compliance with the standard as specified in this section. During the initial compliance demonstration, maximum or minimum operating parameter levels, as appropriate, shall be established for emission sources that will indicate the source is in compliance. Test data, calculations, or information from the evaluation of the control device design shall be used to establish the operating parameter level.

(b) *Monitoring for control devices*—(1) *Parameters to monitor*. Except as specified in paragraph (b)(1)(i) of this section, for each control device, the owner or operator shall install and operate monitoring devices and operate within the established parameter levels to ensure continued compliance with the standard. Monitoring parameters are specified for control scenarios in Table 4 of this subpart and in paragraphs (b)(1)(ii) through (xi) of this section.

(i) *Periodic verification*. For control devices that control vent streams totaling less than 1 ton/yr HAP emissions, before control, monitoring shall consist of a daily verification that the device is operating properly. If the control device is used to control batch process vents alone or in combination with other streams, the verification may be on a per batch basis. This verification shall include, but not be limited to, a daily or per batch demonstration that the unit is working as

designed and may include the daily measurements of the parameters described in (b)(1)(ii) through (x) of this section. This demonstration shall be included in the Precompliance report, to be submitted 6 months prior to the compliance date of the standard.

(ii) *Scrubbers*. For affected sources using liquid scrubbers, the owner or operator shall establish a minimum scrubber liquid flow rate or pressure drop as a site-specific operating parameter which must be measured and recorded every 15 minutes during the period in which the scrubber is functioning in achieving the HAP removal required by this subpart. If the scrubber uses a caustic solution to remove acid emissions, the owner or operator shall establish a minimum pH of the effluent scrubber liquid as a site-specific operating parameter which must be monitored at least once a day. As an alternative to measuring pH, you may elect to continuously monitor the caustic strength of the scrubber effluent. The minimum scrubber flowrate or pressure drop shall be based on the conditions anticipated under worst-case conditions, as defined in §63.1257(b)(8)(i).

(A) The monitoring device used to determine the pressure drop shall be certified by the manufacturer to be accurate to within a gage pressure of ± 10 percent of the maximum pressure drop measured.

(B) The monitoring device used for measurement of scrubber liquid flowrate shall be certified by the manufacturer to be accurate within ± 10 percent of the design scrubber liquid flowrate.

(C) The monitoring device shall be calibrated annually.

(iii) *Condensers*. For each condenser, the owner or operator shall establish the maximum condenser outlet gas temperature or product side temperature as a site specific operating parameter which must be measured and recorded at least every 15 minutes during the period in which the condenser is functioning in achieving the HAP removal required by this subpart.

(A) The temperature monitoring device must be accurate to within ± 2 percent of the temperature measured in degrees Celsius or ± 2.5 °C, whichever is greater.

(B) The temperature monitoring device must be calibrated annually.

(iv) *Regenerative carbon adsorbers*. For each regenerative carbon adsorber, the owner or operator shall comply with the provisions in paragraphs (b)(1)(iv)(A) through (F) of this section.

(A) Establish the regeneration cycle characteristics specified in paragraphs (b)(1)(iv)(A)(1) through (4) of this section under worst-case conditions, as defined in §63.1257(b)(8)(i).

(1) Minimum regeneration frequency (i.e., operating time since last regeneration);

(2) Minimum temperature to which the bed is heated during regeneration;

(3) Maximum temperature to which the bed is cooled, measured within 15 minutes of completing the cooling phase; and

(4) Minimum regeneration stream flow.

(B) Monitor and record the regeneration cycle characteristics specified in paragraphs (b)(1)(iv)(B)(1) through (4) of this section for each regeneration cycle.

(1) Regeneration frequency (operating time since end of last regeneration);

(2) Temperature to which the bed is heated during regeneration;

(3) Temperature to which the bed is cooled, measured within 15 minutes of the completion of the cooling phase; and

(4) Regeneration stream flow.

(C) Use a temperature monitoring device that is accurate to within ± 2 percent of the temperature measured in degrees Celsius or ± 2.5 °C, whichever is greater.

(D) Use a regeneration stream flow monitoring device capable of recording the total regeneration stream flow to within ± 10 percent of the established value (i.e., accurate to within ± 10 percent of the reading).

(E) Calibrate the temperature and flow monitoring devices annually.

(F) Conduct an annual check for bed poisoning in accordance with manufacturer's specifications.

(v) *Nonregenerative carbon adsorbers*. For each nonregenerative carbon adsorber, the owner or operator shall establish and monitor the maximum time interval between replacement based on the conditions anticipated under worst-case, as defined in §63.1257(b)(8)(i).

(vi) *Flares*. For each flare, the presence of the pilot flame shall be monitored every 15 minutes during the period in which the flare is functioning in achieving the HAP removal required by this subpart.

(vii) *Thermal incinerators*. For each thermal incinerator, the owner or operator shall establish the minimum temperature of the gases exiting the combustion chamber as the site-specific operating parameter which must be measured and recorded at least once every 15 minutes during the period in which the combustion device is functioning in achieving the HAP removal required by this subpart.

(A) The temperature monitoring device must be accurate to within ± 0.75 percent of the temperature measured in degrees Celsius or ± 2.5 °C, whichever is greater.

(B) The monitoring device must be calibrated annually.

(viii) *Catalytic incinerators*. For each catalytic incinerator, the owner or operator shall monitor the temperature of the gas stream immediately before and after the catalyst bed. The owner or

operator shall establish the minimum temperature of the gas stream immediately before the catalyst bed and the minimum temperature difference across the catalyst bed as the site-specific operating parameter which must be monitored and recorded at least once every 15 minutes during the period in which the catalytic incinerator is functioning in achieving the HAP removal required by this subpart.

(A) The temperature monitoring devices must be accurate to within ± 0.75 percent of the temperature measured in degrees Celsius or ± 2.5 °C, whichever is greater.

(B) The temperature monitoring devices must be calibrated annually.

(ix) *Process heaters and boilers.* (A) Except as specified in paragraph (b)(1)(ix)(B) of this section, for each boiler or process heater, the owner or operator shall establish the minimum temperature of the gases exiting the combustion chamber as the site-specific operating parameter which must be monitored and recorded at least once every 15 minutes during the period in which the boiler or process heater is functioning in achieving the HAP removal required by this subpart.

(1) The temperature monitoring device must be accurate to within ± 0.75 percent of the temperature measured in degrees Celsius or ± 2.5 °C, whichever is greater.

(2) The temperature monitoring device must be calibrated annually.

(B) The owner or operator is exempt from the monitoring requirements specified in paragraph (b)(1)(ix)(A) of this section if either:

(1) All vent streams are introduced with primary fuel; or

(2) The design heat input capacity of the boiler or process heater is 44 megawatts or greater.

(x) *Continuous emission monitor.* As an alternative to the parameters specified in paragraphs (b)(1)(ii) through (ix) of this section, an owner or operator may monitor and record the outlet HAP concentration or both the outlet TOC concentration and outlet hydrogen halide and halogen concentration every 15 minutes during the period in which the control device is functioning in achieving the HAP removal required by this subpart. The owner or operator need not monitor the hydrogen halide and halogen concentration if, based on process knowledge, the owner or operator determines that the emission stream does not contain hydrogen halides or halogens. The HAP or TOC monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of part 60 and must be installed, calibrated, and maintained, according to §63.8. As part of the QA/QC Plan, calibration of the device must include, at a minimum, quarterly cylinder gas audits.

(xi) *CVS visual inspections.* The owner or operator shall perform monthly visual inspections of each closed vent system as specified in §63.1252(b).

(2) *Averaging periods.* Averaging periods for parametric monitoring levels shall be established according to paragraphs (b)(2)(i) through (iii) of this section.

(i) Except as provided in paragraph (b)(2)(iii) of this section, a daily (24-hour) or block average shall be calculated as the average of all values for a monitored parameter level set according to the procedures in (b)(3)(iii) of this section recorded during the operating day or block.

(ii) The operating day or block shall be defined in the Notification of Compliance Status report. The daily average may be from midnight to midnight or another continuous 24-hour period. The block average is limited to a period of time that is, at a maximum, equal to the time from the beginning to end of a batch process.

(iii) Monitoring values taken during periods in which the control devices are not functioning in controlling emissions, as indicated by periods of no flow, shall not be considered in the averages. Where flow to the device could be intermittent, the owner or operator shall install, calibrate and operate a flow indicator at the inlet or outlet of the control device to identify periods of no flow.

(3) *Procedures for setting parameter levels for control devices used to control emissions*—(i) *Small control devices.* Except as provided in paragraph (b)(1)(i) of this section, for devices controlling less than 10 tons per year of HAP for which a performance test is not required, the parametric levels shall be set based on the design evaluation required in §63.1257(d)(3)(i). If a performance test is conducted, the monitoring parameter level shall be established according to the procedures in (b)(3)(ii) of this section.

(ii) *Large control devices.* For devices controlling greater than 10 tons per year of HAP for which a performance test is required, the parameter level must be established as follows:

(A) If the operating parameter level to be established is a maximum, it must be based on the average of the values from each of the three test runs.

(B) If the operating parameter level to be established is a minimum, it must be based on the average of the values from each of the three test runs.

(C) The owner or operator may establish the parametric monitoring level(s) based on the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of expected parameter values. The rationale for the specific level for each parameter, including any data and calculations used to develop the level(s) and a description of why the level indicates proper operation of the control device shall be provided in the Precompliance report. The procedures specified in this section have not been approved by the Administrator and determination of the parametric monitoring level using these procedures is subject to review and approval by the Administrator.

(iii) *Parameters for control devices controlling batch process vents.* For devices controlling batch process vents alone or in combination with other streams, the parameter level(s) shall be established in accordance with paragraph (b)(3)(iii)(A) or (B) of this section.

(A) If more than one batch emission episode has been selected to be controlled, a single level for the batch process(es) shall be determined from the initial compliance demonstration.

(B) Instead of establishing a single level for the batch process(es), as described in paragraph (b)(3)(iii)(A) of this section, an owner or operator may establish separate levels for each batch emission episode, selected to be controlled. If separate monitoring levels are established, the owner or operator must provide a record indicating at what point in the daily schedule or log of processes required to be recorded per the requirements of §63.1259(b)(9) the parameter being monitored changes levels and must record at least one reading of the new parameter level, even if the duration of monitoring for the new parameter is less than 15-minutes.

(4) *Request approval to monitor alternative parameters.* An owner or operator may request approval to monitor parameters other than those required by paragraphs (b)(1)(ii) through (ix) of this section. The request shall be submitted according to the procedures specified in §63.8(f) or included in the Precompliance report.

(5) *Monitoring for the alternative standards.* (i) For control devices that are used to comply with the provisions of §63.1253(d) or §63.1254(c), the owner or operator shall monitor and record the outlet TOC concentration and the outlet hydrogen halide and halogen concentration every 15 minutes during the period in which the device is functioning in achieving the HAP removal required by this subpart using CEMS as specified in paragraphs (b)(5)(i)(A) through (D) of this section.

(A) A TOC monitor meeting the requirements of EPA Performance Specification 8, 9, or 15 of appendix B of 40 CFR part 60 shall be installed, calibrated, and maintained according to §63.8.

(B) Except as specified in paragraphs (b)(5)(i)(C) and (D) of this section, the owner or operator must monitor HCl using either a FTIR CEMS that meets Performance Specification 15 of appendix B of part 60 or any other CEMS capable of measuring HCl for which a performance specification has been promulgated in appendix B of part 60. To monitor HCl with a CEMS for which a performance specification has not been promulgated, the owner or operator must prepare a monitoring plan and submit it for approval in accordance with the procedures specified in §63.8.

(C) As an alternative to using a CEMS as specified in paragraph (b)(5)(i)(B) of this section to monitor halogenated vent streams that are controlled by a combustion device followed by a scrubber, the owner or operator may elect to monitor scrubber operating parameters as specified in paragraph (b)(1)(ii) of this section that demonstrate the HCl emissions are reduced by at least 95 percent by weight.

(D) The owner or operator need not monitor the hydrogen halide and halogen concentration if, based on process knowledge, the owner or operator determines that the emission stream does not contain hydrogen halides or halogens.

(ii) An owner or operator complying with the alternative standard using control devices in which supplemental gases are added to the vents or manifolds must either correct for supplemental gases as specified in §63.1257(a)(3) or comply with the requirements of paragraph (b)(5)(ii)(A) or (B) of this section. If the owner or operator corrects for supplemental gases as specified in

§63.1257(a)(3)(ii) for noncombustion control devices, the flow rates must be evaluated as specified in paragraph (b)(5)(ii)(C) of this section.

(A) *Provisions for combustion devices.* As an alternative to correcting for supplemental gases as specified in §63.1257(a)(3), the owner or operator may monitor residence time and firebox temperature according to the requirements of paragraphs (b)(5)(ii)(A)(1) and (2) of this section. Monitoring of residence time may be accomplished by monitoring flowrate into the combustion chamber.

(1) If complying with the alternative standard instead of achieving a control efficiency of 95 percent or less, the owner or operator must maintain a minimum residence time of 0.5 seconds and a minimum combustion chamber temperature of 760 °C.

(2) If complying with the alternative standard instead of achieving a control efficiency of 98 percent, the owner or operator must maintain a minimum residence time of 0.75 seconds and a minimum combustion chamber temperature of 816 °C.

(B) *Provisions for dense gas systems.* As an alternative to correcting for supplemental gases as specified in §63.1257(a)(3), for noncombustion devices used to control emissions from dense gas systems, as defined in §63.1251, the owner or operator shall monitor flowrate as specified in paragraphs (b)(5)(ii)(B)(1) through (4) of this section.

(1) Use Equation 63 of this subpart to calculate the system flowrate setpoint at which the average concentration is 5,000 ppmv TOC:

$$F_s = \frac{721 \times E_{an}}{5,000} \quad (\text{Eq. 63})$$

Where:

F_s = system flowrate setpoint, scfm

E_{an} = annual emissions entering the control device, lbmols/yr

(2) Annual emissions used in Equation 63 of this subpart must be based on the actual mass of organic compounds entering the control device, as calculated from the most representative emissions inventory data submitted within the 5 years before the Notification of Compliance Status report is due. The owner or operator must recalculate the system flowrate setpoint once every 5 years using the annual emissions from the most representative emissions inventory data submitted during the 5-year period after the previous calculation. Results of the initial calculation must be included in the Notification of Compliance Status report, and recalculated values must be included in the next Periodic report after each recalculation. For all calculations after the initial calculation, to use emissions inventory data calculated using procedures other than those specified in §63.1257(d), the owner or operator must submit the emissions inventory data calculations and rationale for their use in the Notification of Process Change report or an application for a part 70 permit renewal or revision.

(3) In the Notification of Compliance Status report, the owner or operator may elect to establish both a maximum daily average operating flowrate limit above the flowrate setpoint and a reduced outlet concentration limit corresponding to this flowrate limit. The owner or operator may also establish reduced outlet concentration limits for any daily average flowrates between the flowrate setpoint and the flowrate limit. The correlation between these elevated flowrates and the corresponding outlet concentration limits must be established using Equation 64 of this subpart:

$$C_a = \frac{F_s}{F_a} \times 50 \quad (\text{Eq. 64})$$

Where:

C_a = adjusted outlet concentration limit, dry basis, ppmv

50 = outlet concentration limit associated with the flowrate setpoint, dry basis, ppmv

F_s = system flowrate setpoint, scfm

F_a = actual system flowrate limit, scfm

(4) The owner or operator must install and operate a monitoring system for measuring system flowrate. The flowrate into the control device must be monitored and recorded at least once every hour. The system flowrate must be calculated as the average of all values measured during each 24-hour operating day. The flowrate monitoring device must be accurate to within 5 percent of the system flowrate setpoint, and the flowrate monitoring device must be calibrated annually.

(C) *Flow rate evaluation for noncombustion devices.* To demonstrate continuous compliance with the requirement to correct for supplemental gases as specified in §63.1257(a)(3)(ii) for noncombustion devices, the owner or operator must evaluate the volumetric flow rate of supplemental gases, V_s , and the volumetric flow rate of all gases, V_a , each time a new operating scenario is implemented based on process knowledge and representative operating data. The procedures used to evaluate the flow rates, and the resulting correction factor used in Equation 7B of this subpart, must be included in the Notification of Compliance Status report and in the next Periodic report submitted after an operating scenario change.

(6) *Exceedances of operating parameters.* An exceedance of an operating parameter is defined as one of the following:

(i) If the parameter, averaged over the operating day or block, is below a minimum value established during the initial compliance demonstration.

(ii) If the parameter, averaged over the operating day or block, is above the maximum value established during the initial compliance demonstration.

(iii) Each loss of all pilot flames for flares.

(7) *Excursions.* Excursions are defined by either of the two cases listed in paragraphs (b)(7)(i) or (ii) of this section.

(i) When the period of control device operation is 4 hours or greater in an operating day and monitoring data are insufficient to constitute a valid hour of data, as defined in paragraph (b)(7)(iii) of this section, for at least 75 percent of the operating hours.

(ii) When the period of control device operation is less than 4 hours in an operating day and more than one of the hours during the period of operation does not constitute a valid hour of data due to insufficient monitoring data.

(iii) Monitoring data are insufficient to constitute a valid hour of data, as used in paragraphs (b)(7)(i) and (ii) of this section, if measured values are unavailable for any of the required 15-minute periods within the hour.

(8) *Violations.* Exceedances of parameters monitored according to the provisions of paragraphs (b)(1)(ii), (iv) through (ix), and (b)(5)(ii)(A) and (B) of this section, or excursions as defined by paragraphs (b)(7)(i) through (iii) of this section, constitute violations of the operating limit according to paragraphs (b)(8)(i), (ii), and (iv) of this section. Exceedances of the temperature limit monitored according to the provisions of paragraph (b)(1)(iii) of this section or exceedances of the outlet concentrations monitored according to the provisions of paragraph (b)(1)(x) of this section constitute violations of the emission limit according to paragraphs (b)(8)(i), (ii), and (iv) of this section. Exceedances of the outlet concentrations monitored according to the provisions of paragraph (b)(5) of this section constitute violations of the emission limit according to the provisions of paragraphs (b)(8)(iii) and (iv) of this section.

(i) Except as provided in paragraph (b)(8)(iv) of this section, for episodes occurring more than once per day, exceedances of established parameter limits or excursions will result in no more than one violation per operating day for each monitored item of equipment utilized in the process.

(ii) Except as provided in paragraph (b)(8)(iv) of this section, for control devices used for more than one process in the course of an operating day, exceedances or excursions will result in no more than one violation per operating day, per control device, for each process for which the control device is in service.

(iii) Except as provided in paragraph (b)(8)(iv) of this section, exceedances of the 20 or 50 ppmv TOC outlet emission limit, averaged over the operating day, will result in no more than one violation per day per control device. Except as provided in paragraph (b)(8)(iv) of this section, exceedances of the 20 or 50 ppmv hydrogen halide or halogen outlet emission limit, averaged over the operating day, will result in no more than one violation per day per control device.

(c) *Monitoring for emission limits.* The owner or operator of any affected source complying with the provisions of §63.1254(a)(2) shall demonstrate continuous compliance with the 900 and 1,800 kg/yr emission limits by calculating daily 365-day rolling summations of emissions. During periods of planned routine maintenance when emissions are controlled as specified in

§63.1252(h), the owner or operator must calculate controlled emissions assuming the HAP emissions are reduced by 93 percent. For any owner or operator opting to switch compliance strategy from the 93 percent control requirement to the annual mass emission limit method, as described in §63.1254(a)(1)(i), the rolling summations, beginning with the first day after the switch, must include emissions from the past 365 days.

(d) *Monitoring for equipment leaks.* The owner or operator of any affected source complying with the requirements of §63.1255 of this subpart shall meet the monitoring requirements described §63.1255 of this subpart.

(e) *Pollution prevention.* The owner or operator of any affected source that chooses to comply with the requirements of §§63.1252(e)(2) and (3) shall calculate a yearly rolling average of kg HAP consumption per kg production and kg VOC consumption per kg production every month or every 10 batches. Each rolling average kg/kg factor that exceeds the value established in §63.1257(f)(1)(ii) will be considered a violation of the emission limit.

(f) *Emissions averaging.* The owner or operator of any affected source that chooses to comply with the requirements of §63.1252(d) shall meet all monitoring requirements specified in paragraphs (b)(1) and (3) of this section, as applicable, for all processes and storage tanks included in the emissions average.

(g) *Inspection and monitoring of waste management units and treatment processes.* (1) For each wastewater tank, surface impoundment, container, individual drain system, and oil-water separator that receives, manages, or treats wastewater, a residual removed from wastewater, a recycled wastewater, or a recycled residual removed from wastewater, the owner or operator shall comply with the inspection requirements specified in Table 7 of this subpart.

(2) For each biological treatment unit used to comply with §63.1256(g), the owner or operator shall monitor TSS, BOD, and the biomass concentration at a frequency approved by the permitting authority and using methods approved by the permitting authority. The owner or operator may request approval to monitor other parameters. The request shall be submitted in the Precompliance report according to the procedures specified in §63.1260(e), and shall include a description of planned reporting and recordkeeping procedures. The owner or operator shall include as part of the submittal the basis for the selected monitoring frequencies and the methods that will be used. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application or by other appropriate means.

(3) For nonbiological treatment units, the owner or operator shall request approval to monitor appropriate parameters that demonstrate proper operation of the selected treatment process. The request shall be submitted in the Precompliance report according to the procedures specified in §63.1260(e), and shall include a description of planned reporting and recordkeeping procedures. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application or by other appropriate means.

(h) *Leak inspection provisions for vapor suppression equipment.* (1) Except as provided in paragraph (h)(9) and (10) of this section, for each vapor collection system, closed-vent system,

fixed roof, cover, or enclosure required to comply with this section, the owner or operator shall comply with the requirements of paragraphs (h)(2) through (8) of this section.

(2) Except as provided in paragraphs (h)(6) and (7) of this section, each vapor collection system and closed-vent system shall be inspected according to the procedures and schedule specified in paragraphs (h)(2)(i) and (ii) of this section and each fixed roof, cover, and enclosure shall be inspected according to the procedures and schedule specified in paragraph (h)(2)(iii) of this section.

(i) If the vapor collection system or closed-vent system is constructed of hard-piping, the owner or operator shall:

(A) Conduct an initial inspection according to the procedures in paragraph (h)(3) of this section, and

(B) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(ii) If the vapor collection system or closed-vent system is constructed of ductwork, the owner or operator shall:

(A) Conduct an initial inspection according to the procedures in paragraph (h)(3) of this section, and

(B) Conduct annual inspections according to the procedures in paragraph (h)(3) of this section.

(C) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(iii) For each fixed roof, cover, and enclosure, the owner or operator shall:

(A) Conduct an initial inspection according to the procedures in paragraph (h)(3) of this section, and

(B) Conduct semiannual visual inspections for visible, audible, or olfactory indications of leaks.

(3) Each vapor collection system, closed-vent system, fixed roof, cover, and enclosure shall be inspected according to the procedures specified in paragraphs (h)(3)(i) through (v) of this section.

(i) Inspections shall be conducted in accordance with Method 21 of 40 CFR part 60, appendix A.

(ii) *Detection instrument performance criteria.* (A) Except as provided in paragraph (h)(3)(ii)(B) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual VOC in the stream. For process streams that contain nitrogen, air, or other inerts which are not organic HAP or VOC, the average stream response factor shall be calculated on an inert-free basis.

(B) If no instrument is available at the plant site that will meet the performance criteria specified in paragraph (h)(3)(ii)(A) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (h)(3)(ii)(A) of this section.

(iii) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21 of 40 CFR part 60, appendix A.

(iv) Calibration gases shall be as follows:

(A) Zero air (less than 10 parts per million hydrocarbon in air); and

(B) Mixtures of methane in air at a concentration less than 10,000 parts per million. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (h)(2)(ii)(A) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(v) An owner or operator may elect to adjust or not adjust instrument readings for background. If an owner or operator elects to not adjust readings for background, all such instrument readings shall be compared directly to the applicable leak definition to determine whether there is a leak. If an owner or operator elects to adjust instrument readings for background, the owner or operator shall measure background concentration using the procedures in §63.180(b) and (c). The owner or operator shall subtract background reading from the maximum concentration indicated by the instrument.

(vi) The background level shall be determined according to the procedures in Method 21 of 40 CFR part 60 appendix A.

(vii) The arithmetic difference between the maximum concentration indicated by the instrument and the background level shall be compared with 500 parts per million for determining compliance.

(4) Leaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual inspections, shall be repaired as soon as practicable, except as provided in paragraph (h)(5) of this section.

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

(ii) Repair shall be completed no later than 15 calendar days after the leak is detected, except as provided in paragraph (h)(4)(iii) of this section.

(iii) For leaks found in vapor collection systems used for transfer operations, repairs shall be completed no later than 15 calendar days after the leak is detected or at the beginning of the next transfer loading operation, whichever is later.

(5) Delay of repair of a vapor collection system, closed-vent system, fixed roof, cover, or enclosure for which leaks have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in §63.1251, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next shutdown.

(6) Any parts of the vapor collection system, closed-vent system, fixed roof, cover, or enclosure that are designated, as described in paragraph (h)(8) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (h)(2)(i), (ii), and (iii) of this section if:

(i) The owner or operator determines 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 (h)(2)(i), (ii), or (iii) of this section; and

(ii) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) Any parts of the vapor collection system, closed-vent system, fixed roof, cover, or enclosure that are designated, as described in paragraph (h)(8) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (h)(2)(i), (ii), and (iii)(A) of this section if:

(i) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(ii) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

(8) Records shall be maintained as specified in §63.1259(i) (4) through (9).

(9) If a closed-vent system subject to this section is also subject to the equipment leak provisions of §63.1255, the owner or operator shall comply with the provisions of §63.1255 and is exempt from the requirements of this section.

(10) Instead of complying with the provisions of paragraphs (h)(2) through (8) of this section, an owner or operator may design a closed-vent system to operate at a pressure below atmospheric pressure. The system shall be equipped with at least one pressure gauge or other pressure measurement device that can be read from a readily accessible location to verify that negative pressure is being maintained in the closed-vent system when the associated control device is operating.

(i) *Planned routine maintenance.* During periods of planned routine maintenance when organic HAP emissions are controlled as specified in §63.1252(h)(2), the owner or operator must monitor the condenser outlet gas temperature according to the procedures specified in paragraph (b)(1)(iii) of this section. During periods of planned routine maintenance when HCl emissions

are controlled as specified in §63.1252(h)(3), the owner or operator must monitor the pH of the scrubber effluent once per day.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52612, Aug. 29, 2000; 66 FR 40134, Aug. 2, 2001; 70 FR 25670, May 13, 2005; 71 FR 20459, Apr. 20, 2006; 76 FR 22601, Apr. 21, 2011]

§63.1259 Recordkeeping requirements.

(a) *Requirements of subpart A of this part.* The owner or operator of an affected source shall comply with the recordkeeping requirements in subpart A of this part as specified in Table 1 of this subpart and in paragraphs (a)(1) through (5) of this section.

(1) *Data retention.* Each owner or operator of an affected source shall keep copies of all records and reports required by this subpart for at least 5 years, as specified in §63.10(b)(1).

(2) *Records of applicability determinations.* The owner or operator of a stationary source that is not subject to this subpart shall keep a record of the applicability determination, as specified in §63.10(b)(3).

(3) *Malfunction records.* Each owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment), air pollution control equipment, or monitoring equipment. Each owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with §63.1250(g)(3), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(4) *Recordkeeping requirements for sources with continuous monitoring systems.* The owner or operator of an affected source who elects to install a continuous monitoring system shall maintain records specified in §63.10(c)(1) through (14).

(5) *Application for approval of construction or reconstruction.* For new affected sources, each owner or operator shall comply with the provisions in §63.5 regarding construction and reconstruction, excluding the provisions specified in §63.5(d)(1)(ii)(H), (d)(2), and (d)(3)(ii).

(b) *Records of equipment operation.* The owner or operator must keep the following records up-to-date and readily accessible:

(1) Each measurement of a control device operating parameter monitored in accordance with §63.1258 and each measurement of a treatment process parameter monitored in accordance with §63.1258(g)(2) and (3).

(2) For processes subject to §63.1252(e), records of consumption, production, and the rolling average values of the production-indexed HAP and VOC consumption factors.

(3) For each continuous monitoring system used to comply with this subpart, records documenting the completion of calibration checks and maintenance of continuous monitoring systems.

(4) For purposes of compliance with the annual mass limits of §63.1254(a)(2) and (b)(2), daily records of the rolling annual total emissions.

(5) Records of the following, as appropriate:

(i) For processes that are in compliance with the percent reduction requirements of §63.1254(a)(1) or (b)(1) and that contain vents controlled to less than the percent reduction requirement, the records specified in paragraphs (b)(5)(i)(A) through (C) of this section are required.

(A) Standard batch uncontrolled and controlled emissions for each process;

(B) Actual uncontrolled and controlled emissions for each nonstandard batch; and

(C) A record whether each batch operated was considered a standard batch.

(ii) For processes in compliance with the annual mass limits of §63.1254(a)(2) or (b)(2), the following records are required:

(A) The number of batches per year for each batch process;

(B) The operating hours per year for continuous processes;

(C) Standard batch uncontrolled and controlled emissions for each process;

(D) Actual controlled emissions for each batch operated during periods of planned routine maintenance of a CCCD, calculated according to §63.1258(c).

(E) Actual uncontrolled and controlled emissions for each nonstandard batch;

(F) A record whether each batch operated was considered a standard batch.

(6) Wastewater concentration per POD or process, except as provided in §63.1256(a)(1)(ii).

(7) Number of storage tank turnovers per year, if used in an emissions average.

(8) A schedule or log of each operating scenario updated daily or, at a minimum, each time a different operating scenario is put into operation.

(9) Description of worst-case operating conditions as required in §63.1257(b)(8).

(10) Periods of planned routine maintenance as described in §§63.1252(h) and 63.1257(c)(5).

(11) If the owner or operator elects to comply with §63.1253(b) or (c) by installing a floating roof, the owner or operator must keep records of each inspection and seal gap measurement in accordance with §63.123(c) through (e) as applicable.

(12) If the owner or operator elects to comply with the vapor balancing alternative in §63.1253(f), the owner or operator must keep records of the DOT certification required by §63.1253(f)(2) and the pressure relief vent setting and the leak detection records specified in §63.1253(f)(5).

(13) All maintenance performed on the air pollution control equipment.

(c) *Records of operating scenarios.* The owner or operator of an affected source shall keep records of each operating scenario which demonstrates compliance with this subpart.

(d) *Records of equipment leak detection and repair programs.* The owner or operator of any affected source implementing the leak detection and repair (LDAR) program specified in §63.1255 of this subpart, shall implement the recordkeeping requirements in §63.1255 of this subpart.

(e) *Records of emissions averaging.* The owner or operator of any affected source that chooses to comply with the requirements of §63.1252(d) shall maintain up-to-date records of the following information:

(1) An Implementation Plan which shall include in the plan, for all process vents and storage tanks included in each of the averages, the information listed in paragraphs (e)(1)(i) through (v) of this section.

(i) The identification of all process vents and storage tanks in each emissions average.

(ii) The uncontrolled and controlled emissions of HAP and the overall percent reduction efficiency as determined in §§63.1257(g)(1) through (4) or 63.1257(h)(1) through (3) as applicable.

(iii) The calculations used to obtain the uncontrolled and controlled HAP emissions and the overall percent reduction efficiency.

(iv) The estimated values for all parameters required to be monitored under §63.1258(f) for each process and storage tank included in an average.

(v) A statement that the compliance demonstration, monitoring, inspection, recordkeeping and reporting provisions in §§63.1257(g) and (h), 63.1258(f), and 63.1260(k) that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

(2) The Implementation Plan must demonstrate that the emissions from the processes and storage tanks proposed to be included in the average will not result in greater hazard or, at the option of

the operating permit authority, greater risk to human health or the environment than if the storage tanks and process vents were controlled according to the provisions in §§63.1253 and 63.1254, respectively.

(i) This demonstration of hazard or risk equivalency shall be made to the satisfaction of the operating permit authority.

(A) The Administrator may require owners and operators to use specific methodologies and procedures for making a hazard or risk determination.

(B) The demonstration and approval of hazard or risk equivalency shall be made according to any guidance that the Administrator makes available for use or any other technically sound information or methods.

(ii) An emissions averaging plan that does not demonstrate hazard or risk equivalency to the satisfaction of the Administrator shall not be approved. The Administrator may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§63.1253 and 63.1254.

(iii) A hazard or risk equivalency demonstration must:

(A) Be a quantitative, comparative chemical hazard or risk assessment;

(B) Account for differences between averaging and non-averaging options in chemical hazard or risk to human health or the environment; and

(C) Meet any requirements set by the Administrator for such demonstrations.

(3) Records as specified in paragraphs (a), (b) and (d) of this section.

(4) A rolling quarterly calculation of the annual percent reduction efficiency as specified in §63.1257(g) and (h).

(f) *Records of delay of repair.* Documentation of a decision to use a delay of repair due to unavailability of parts, as specified in §63.1256(i), shall include a description of the failure, the reason additional time was necessary (including a statement of why replacement parts were not kept onsite and when delivery from the manufacturer is scheduled), and the date when the repair was completed.

(g) *Record of wastewater stream or residual transfer.* The owner or operator transferring an affected wastewater stream or residual removed from an affected wastewater stream in accordance with §63.1256(a)(5) shall keep a record of the notice sent to the treatment operator stating that the wastewater stream or residual contains organic HAP which are required to be managed and treated in accordance with the provisions of this subpart.

(h) *Records of extensions.* The owner or operator shall keep documentation of a decision to use an extension, as specified in §63.1256(b)(6)(ii) or (b)(9), in a readily accessible location. The documentation shall include a description of the failure, documentation that alternate storage capacity is unavailable, and specification of a schedule of actions that will ensure that the control equipment will be repaired and the tank will be emptied as soon as practical.

(i) *Records of inspections.* The owner or operator shall keep records specified in paragraphs (i)(1) through (9) of this section.

(1) A record that each waste management unit inspection required by §63.1256(b) through (f) was performed.

(2) A record that each inspection for control devices required by §63.1256(h) was performed.

(3) A record of the results of each seal gap measurement required by §63.1256(b)(5) and (f)(3). The records shall include the date of measurement, the raw data obtained in the measurement, and the calculations described in §63.120(b)(2) through (4).

(4) Records identifying all parts of the vapor collection system, closed-vent system, fixed roof, cover, or enclosure that are designated as unsafe to inspect in accordance with §63.1258(h)(6), an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(5) Records identifying all parts of the vapor collection system, closed-vent system, fixed roof, cover, or enclosure that are designated as difficult to inspect in accordance with §63.1258(h)(7), an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(6) For each vapor collection system or closed-vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall keep a record of the information specified in either paragraph (i)(6)(i) or (ii) of this section.

(i) Hourly records of whether the flow indicator specified under §63.1252(b)(1) was operating and whether a diversion was detected at any time during the hour, as well as records of the times and durations of all periods when the vent stream is diverted from the control device or the flow indicator is not operating.

(ii) Where a seal mechanism is used to comply with §63.1252(b)(2), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanisms has been done, and shall record the occurrence of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken.

(7) For each inspection conducted in accordance with §63.1258(h)(2) and (3) during which a leak is detected, a record of the information specified in paragraphs (i)(7)(i) through (ix) of this section.

- (i) Identification of the leaking equipment.
- (ii) The instrument identification numbers and operator name or initials, if the leak was detected using the procedures described in §63.1258(h)(3); or a record that the leak was detected by sensory observations.
- (iii) The date the leak was detected and the date of the first attempt to repair the leak.
- (iv) Maximum instrument reading measured by the method specified in §63.1258(h)(4) after the leak is successfully repaired or determined to be nonrepairable.
- (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 name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.
- (vii) The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.
- (viii) Dates of shutdowns that occur while the equipment is unrepaired.
- (ix) The date of successful repair of the leak.
- (8) For each inspection conducted in accordance with §63.1258(h)(3) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- (9) For each visual inspection conducted in accordance with §63.1258(h)(2)(i)(B) or (h)(2)(iii)(B) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52613, Aug. 29, 2000; 66 FR 40135, Aug. 2, 2001; 70 FR 25670, May 13, 2005; 71 FR 20459, Apr. 20, 2006; 76 FR 22601, Apr. 21, 2011]

§63.1260 Reporting requirements.

- (a) The owner or operator of an affected source shall comply with the reporting requirements of paragraphs (b) through (n) of this section. Applicable reporting requirements of §§63.9 and 63.10 are also summarized in Table 1 of this subpart.
- (b) *Initial notification.* The owner or operator shall submit the applicable initial notification in accordance with §63.9(b) or (d).
- (c) *Application for approval of construction or reconstruction.* An owner or operator who is subject to §63.5(b)(3) shall submit to the Administrator an application for approval of the

construction of a new major affected source, the reconstruction of a major affected source, or the reconstruction of a major source such that the source becomes a major affected source subject to the standards. The application shall be prepared in accordance with §63.5(d).

(d) *Notification of CMS performance evaluation.* An owner or operator who is required by the Administrator to conduct a performance evaluation for a continuous monitoring system shall notify the Administrator of the date of the performance evaluation as specified in §63.8(e)(2).

(e) *Precompliance report.* The Precompliance report shall be submitted at least 6 months prior to the compliance date of the standard. For new sources, the Precompliance report shall be submitted to the Administrator with the application for approval of construction or reconstruction. The Administrator shall have 90 days to approve or disapprove the plan. The plan shall be considered approved if the Administrator either approves the plan in writing, or fails to disapprove the plan in writing. The 90 day period shall begin when the Administrator receives the request. If the request is denied, the owner or operator must still be in compliance with the standard by the compliance date. To change any of the information submitted in the report, the owner or operator shall notify the Administrator 90 days before the planned change is to be implemented; the change shall be considered approved if the Administrator either approves the change in writing, or fails to disapprove the change in writing. The Precompliance report shall include:

(1) Requests for approval to use alternative monitoring parameters or requests to set monitoring parameters according to §63.1258(b)(4).

(2) Descriptions of the daily or per batch demonstrations to verify that control devices subject to §63.1258(b)(1)(i) are operating as designed.

(3) A description of test conditions, and the corresponding monitoring parameter values for parameters that are set according to §63.1258(b)(3)(ii)(C).

(4) For owners and operators complying with the requirements of §63.1252(e), the P2 demonstration summary required in §63.1257(f).

(5) Data and rationale used to support an engineering assessment to calculate uncontrolled emissions from process vents as required in §63.1257(d)(2)(ii).

(6) Data and other information supporting the determination of annual average concentrations by process simulation as required in §63.1257(e)(1)(ii).

(7) Bench scale or pilot-scale test data and rationale used to determine annual average concentrations as required in §63.1257(e)(1)(ii)(C).

(f) *Notification of Compliance Status report.* The Notification of Compliance Status report required under §63.9 shall be submitted no later than 150 days after the compliance date and shall include:

(1) The results of any applicability determinations, emission calculations, or analyses used to identify and quantify HAP emissions from the affected source.

(2) The results of emissions profiles, performance tests, engineering analyses, design evaluations, or calculations used to demonstrate compliance. For performance tests, results should include descriptions of sampling and analysis procedures and quality assurance procedures.

(3) Descriptions of monitoring devices, monitoring frequencies, and the values of monitored parameters established during the initial compliance determinations, including data and calculations to support the levels established.

(4) Listing of all operating scenarios.

(5) Descriptions of worst-case operating and/or testing conditions for control devices.

(6) Identification of emission points subject to overlapping requirements described in §63.1250(h) and the authority under which the owner or operator will comply.

(7) Anticipated periods of planned routine maintenance of a CCCD subject to §63.1252(h) during the period between the compliance date and the end of the period covered by the first Periodic report, and if applicable, the rationale for why the planned routine maintenance must be performed while a process with a vent subject to §63.1254(a)(3) will be operating.

(g) *Periodic reports.* An owner or operator shall prepare Periodic reports in accordance with paragraphs (g)(1) and (2) of this section and submit them to the Administrator.

(1) *Submittal schedule.* Except as provided in paragraphs (g)(1)(i), (ii), and (iii) of this section, an owner or operator shall submit Periodic reports semiannually. The first report shall be submitted no later than 240 days after the Notification of Compliance Status is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status is due. Each subsequent Periodic report shall cover the 6-month period following the preceding period.

(i) When the Administrator determines on a case-by-case basis that more frequent reporting is necessary to accurately assess the compliance status of the affected source; or

(ii) Quarterly reports shall be submitted when the source experiences an exceedance of a temperature limit monitored according to the provisions of §63.1258(b)(1)(iii) or an exceedance of the outlet concentration monitored according to the provisions of §63.1258(b)(1)(x) or (b)(5). Once an affected source reports quarterly, the affected source shall follow a quarterly reporting format until a request to reduce reporting frequency is approved. If an owner or operator submits a request to reduce the frequency of reporting, the provisions in §63.10(e)(3)(ii) and (iii) shall apply, except that the phrase “excess emissions and continuous monitoring system performance report and/or summary report” shall mean “Periodic report” for the purposes of this section.

(iii) When a new operating scenario has been operated since the last report, in which case quarterly reports shall be submitted.

(2) *Content of Periodic report.* The owner or operator shall include the information in paragraphs (g)(2)(i) through (vii) of this section, as applicable.

(i) Each Periodic report must include the information in §63.10(e)(3)(vi)(A) through (I) and (K) through (M). For each continuous monitoring system, the Periodic report must also include the information in §63.10(e)(3)(vi)(J).

(ii) If the total duration of excess emissions, parameter exceedances, or excursions for the reporting period is 1 percent or greater of the total operating time for the reporting period, or the total continuous monitoring system downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the Periodic report must include the information in paragraphs (g)(2)(ii)(A) through (D) of this section.

(A) Monitoring data, including 15-minute monitoring values as well as daily average values of monitored parameters, for all operating days when the average values were outside the ranges established in the Notification of Compliance Status report or operating permit.

(B) Duration of excursions, as defined in §63.1258(b)(7).

(C) Operating logs and operating scenarios for all operating scenarios for all operating days when the values are outside the levels established in the Notification of Compliance Status report or operating permit.

(D) When a continuous monitoring system is used, the information required in §63.10(c)(5) through (13).

(iii) For each inspection conducted in accordance with §63.1258(h)(2) or (3) during which a leak is detected, the records specified in §63.1259(i)(7) must be included in the next Periodic report.

(iv) For each vapor collection system or closed vent system with a bypass line subject to §63.1252(b)(1), records required under §63.1259(i)(6)(i) of all periods when the vent stream is diverted from the control device through a bypass line. For each vapor collection system or closed vent system with a bypass line subject to §63.1252(b)(2), records required under §63.1259(i)(6)(ii) of all periods in which the seal mechanism is broken, the bypass valve position has changed, or the key to unlock the bypass line valve was checked out.

(v) The information in paragraphs (g)(2)(v)(A) through (D) of this section shall be stated in the Periodic report, when applicable.

(A) No excess emissions.

(B) No exceedances of a parameter.

(C) No excursions.

(D) No continuous monitoring system has been inoperative, out of control, repaired, or adjusted.

(vi) The information specified in paragraphs (g)(2)(vi)(A) through (C) for periods of planned routine maintenance.

(A) For each storage tank subject to control requirements, periods of planned routine maintenance during which the control device does not meet the specifications of §63.1253(b) through (d).

(B) For a CCCD subject to §63.1252(h), periods of planned routine maintenance during the current reporting period and anticipated periods of planned routine maintenance during the next reporting period.

(C) Rationale for why planned routine maintenance of a CCCD subject to §63.1252(h) must be performed while a process with a vent subject to §63.1254(a)(3) will be operating, if applicable. This requirement applies only if the rationale is not in, or differs from that in, the Notification of Compliance Status report.

(vii) Each new operating scenario which has been operated since the time period covered by the last Periodic report. For each new operating scenario, the owner or operator shall provide verification that the operating conditions for any associated control or treatment device have not been exceeded, and that any required calculations and engineering analyses have been performed. For the initial Periodic report, each operating scenario for each process operated since the due date of the Notification of Compliance Status Report shall be submitted.

(viii) If the owner or operator elects to comply with the provisions of §63.1253(b) or (c) by installing a floating roof, the owner or operator shall submit the information specified in §63.122(d) through (f) as applicable. References to §63.152 from §63.122 shall not apply for the purposes of this subpart.

(h) *Notification of process change.* (1) Except as specified in paragraph (h)(2) of this section, whenever a process change is made, or a change in any of the information submitted in the Notification of Compliance Status Report, the owner or operator shall submit the information specified in paragraphs (h)(1)(i) through (iv) of this section with the next Periodic report required under paragraph (g) of this section.

(i) A brief description of the process change.

(ii) A description of any modifications to standard procedures or quality assurance procedures.

(iii) Revisions to any of the information reported in the original Notification of Compliance Status Report under paragraph (f) of this section.

(iv) Information required by the Notification of Compliance Status Report under paragraph (f) of this section for changes involving the addition of processes or equipment.

(2) An owner or operator must submit a report 60 days before the scheduled implementation date of either of the following:

(i) Any change in the activity covered by the Precompliance report.

(ii) A change in the status of a control device from small to large.

(i) The owner or operator shall submit a report of the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.1250(g)(3), including actions taken to correct a malfunction. The report shall be submitted on the same schedule as the periodic reports required under paragraph (g) of this section.

(j) *Reports of LDAR programs.* The owner or operator of any affected source implementing the LDAR program specified in §63.1255 of this subpart shall implement the reporting requirements in §63.1255 of this subpart. Copies of all reports shall be retained as records for a period of 5 years, in accordance with the requirements of §63.10(b)(1).

(k) *Reports of emissions averaging.* The owner or operator of any affected source that chooses to comply with the requirements of §63.1252(d) shall submit the implementation plan described in §63.1259(e) 6 months prior to the compliance date of the standard and the following information in the periodic reports:

(1) The records specified in §63.1259(e) for each process or storage tank included in the emissions average;

(2) All information as specified in paragraph (g) of this section for each process or storage tank included in the emissions average;

(3) Any changes of the processes or storage tanks included in the average.

(4) The calculation of the overall percent reduction efficiency for the reporting period.

(5) Changes to the Implementation Plan which affect the calculation methodology of uncontrolled or controlled emissions or the hazard or risk equivalency determination.

(6) Every second semiannual or fourth quarterly report, as appropriate, shall include the results according to §63.1259(e)(4) to demonstrate the emissions averaging provisions of §§63.1252(d), 63.1257(g) and (h), 63.1258(f), and 63.1259(f) are satisfied.

(l) *Notification of performance test and test plan.* The owner or operator of an affected source shall notify the Administrator of the planned date of a performance test at least 60 days before the test in accordance with §63.7(b). The owner or operator also must submit the test plan required by §63.7(c) and the emission profile required by 63.1257(b)(8)(ii) with the notification of the performance test.

(m) *Request for extension of compliance.* An owner or operator may submit to the Administrator a request for an extension of compliance in accordance with §63.1250(f)(4).

(n)(1) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in §63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange by using the ERT (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (n)(1) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (n)(1) of this section in paper format.

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52614, Aug. 29, 2000; 66 FR 40135, Aug. 2, 2001; 76 FR 22601, Apr. 21, 2011]

§63.1261 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.1250 and 63.1252 through 63.1256. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37356, June 23, 2003]

Table 1 to Subpart GGG of Part 63—General Provisions Applicability to Subpart GGG

General provisions reference	Summary of requirements	Applies to subpart GGG	Comments
63.1(a)(1)	General applicability of the General Provisions	Yes	Additional terms defined in §63.1251; when overlap between subparts A and GGG of this part, subpart GGG takes precedence.
63.1(a)(2-7)		Yes	
63.1(a)(8)		No	Discusses state programs.
63.1(a)(9-14)		Yes	
63.1(b)(1)	Initial applicability determination	Yes	Subpart GGG clarifies the applicability in §63.1250.
63.1(b)(2)	Title V operating permit—see part 70	Yes	All major affected sources are required to obtain a title V permit.
63.1(b)(3)	Record of the applicability determination	Yes	All affected sources are subject to subpart GGG according to the applicability definition of subpart GGG.
63.1(c)(1)	Applicability after standards are set	Yes	Subpart GGG clarifies the applicability of each paragraph of subpart A to sources subject to subpart GGG.
63.1(c)(2)	Title V permit requirement	No	All major affected sources are required to obtain a title V permit. Area sources are not subject to subpart GGG.

63.1(c)(3)	Reserved		
63.1(c)(4)	Requirements for existing source that obtains an extension of compliance	Yes	
§63.1(c)(5)	Notification requirements for an area source that increases HAP emissions to major source levels	Yes	
63.1(d)	[Reserved]	NA	
63.1(e)	Applicability of permit program before a relevant standard has been set	Yes	
63.2	Definitions.	Yes	Additional terms defined in §63.1251; when overlap between subparts A and GGG of this part occurs, subpart GGG takes precedence.
63.3	Units and abbreviations.	Yes	Other units used in subpart GGG are defined in that subpart.
63.4	Prohibited activities.	Yes	
63.5(a)	Construction and reconstruction—applicability	Yes	Except replace the terms “source” and “stationary source” with “affected source”.
63.5(b)(1)	Upon construction, relevant standards for new sources	Yes	
63.5(b)(2)	[Reserved]	NA	
63.5(b)(3)	New construction/reconstruction	Yes	Except for changes and additions authorized under §52.2454 of this title. However, the requirement to submit the Precompliance report at least 90 days before the compliance date still applies.
63.5(b)(4)	Construction/reconstruction notification	Yes	
63.5(b)(5)	Construction/reconstruction compliance	Yes	
63.5(b)(6)	Equipment addition or process change	Yes	
63.5(c)	[Reserved]	NA	
63.5(d)	Application for approval of construction/reconstruction	Yes	Except for certain provisions identified in 63.1259(a)(5)

§63.5(e)	Construction/reconstruction approval	Yes	
63.5(f)	Construction/reconstruction approval based on prior State review.	Yes	Except replace “source” with “affected source”.
63.6(a)(1)	Compliance with standards and maintenance requirements	Yes	
63.6(a)(2)	Requirements for area source that increases emissions to become major	Yes	
63.6(b)(1-2)	Compliance dates for new and reconstructed sources	No	Subpart GGG specifies compliance dates.
63.6(b)(3-6)	Compliance dates for area sources that become major sources	Yes	
63.6 (b)(7)	Compliance dates for new sources resulting from new unaffected area sources becoming subject to standards	No	Subpart GGG specifies NS applicability and compliance dates
63.6(c)	Compliance dates for existing sources	Yes	Except replace “source” with “affected source”. Subpart GGG specifies compliance dates.
§63.6(e)(1)(i)	Requirements during periods of startup, shutdown, and malfunction	No	See 63.1250(g)(3) for general duty requirement. Any cross-reference to 63.6(e)(1)(i) in any other general provision incorporated by reference shall be treated as a cross-reference to 63.1250(g)(3).
§63.6(e)(1)(ii)	Malfunction correction requirements	No.	
§63.6(e)(1)(iii)	Enforceability of operation and maintenance requirements	Yes.	
§63.6(e)(2)	Reserved	No	Section reserved.
§63.6(e)(3)	Startup, shutdown, and malfunction plan requirements	No.	
63.6(f)(1)	Applicability of nonopacity emission standards	No.	
63.6(f)(2)-(3)	Methods of determining compliance and findings compliance	Yes.	
63.6(g)	Use of an alternative nonopacity emission standard	Yes.	

63.6(h)	Opacity and visible emission standards	No	Subpart GGG does not contain any opacity or visible emission standards.
§63.6(i)(1) through (7)	Requests for compliance extensions	No	§63.1250(f)(6) specifies provisions for compliance extensions.
§63.6(i)(8) through (14)	Approval of compliance extensions	Yes	Except references to §63.6(i)(4) through (6) mean §63.1250(f)(6).
63.6(j)	Exemption from compliance with emission standards	Yes	
63.7(a)(1)	Performance testing requirements	Yes	Subpart GGG also specifies required testing and compliance procedures.
63.7(a)(2)(i)-(ix)		Yes	Except substitute “150 days” instead of “180 days.”
63.7(a)(3)		Yes	
63.7(b)(1)	Notification of performance test	Yes	
63.7(b)(2)	Notification of delay in conducting a scheduled performance test	Yes	
63.7(c)	Quality assurance program	Yes	Except that the test plan must be submitted with the notification of the performance test.
63.7(d)	Performance testing facilities.	Yes	Except replace “source” with “affected source”.
63.7(e)(1)	Conduct of performance tests	No	See 63.1257(a) text. Any cross-reference to 63.7(e)(1) in any other general provision incorporated by reference shall be treated as a cross-reference to 63.1257(a).
63.7(e)(2)-(4)	Performance tests requirements	Yes.	
63.7(f)	Use of alternative test method	Yes	
63.7(g)	Data analysis, recordkeeping, and reporting	Yes	
63.7(h)	Waiver of performance tests	Yes	
63.8(a)	Monitoring requirements	Yes	See §63.1258.
63.8(b)(1)	Conduct of monitoring	Yes	
63.8(b)(2)	CMS and combined effluents	No	§63.1258 of subpart GGG provides specific CMS requirements.

63.8(b)(3)-(c)(4)	CMS requirements	Yes	§63.1259 also specifies recordkeeping for CMS.
63.8(c)(5)	COMS operation requirements	No	
63.8(c)(6)-(8)	CMS calibration and malfunction provisions	No	Calibration procedures are provided in §63.1258.
63.8(d)(1)-(2)	CMS quality control program requirements	Yes.	
63.8(d)(3)	CMS quality control program recordkeeping requirements	Yes, except for last sentence	
63.8(e)(1)	Performance evaluations of CMS	Yes	
63.8(e)(2)	Notification of performance evaluation	Yes	
63.8(e)(3-4)	CMS requirements/alternatives	Yes	
§63.8(e)(5)(i)	Reporting performance evaluation results	Yes	See §63.1260(a).
63.1260 (a).			
63.8(e)(5)(ii)	Results of COMS performance evaluation	No	Subpart GGG does not contain any opacity or visible emission standards.
63.8(f)-(g)	Alternative monitoring method/reduction of monitoring data	Yes	
63.9(a)-(d)	Notification requirements—Applicability and general information	Yes	§63.1260 (b) also specifies initial notification requirement.
63.9(e)	Notification of performance test	Yes	§63.1260 (l) also specifies notification requirement for performance test.
63.9(f)	Notification of opacity and visible emissions observations	No	Subpart GGG does not contain any opacity or visible emission standards.
63.9(g)(1)	Additional notification requirements for sources with CMS	Yes	§63.1260 (d) also specifies notification requirement for performance evaluation.
63.9(g)(2)	Notification of compliance with opacity emission standard	No	Subpart GGG does not contain any opacity or visible emission standards.
63.9(g)(3)	Notification that criterion to continue use of alternative to relative accuracy testing has been	Yes	§63.1260 (d) also specifies notification requirement for performance evaluation.

	exceeded		
63.9(h)	Notification of compliance status	Yes	Specified in §63.1260(f). Due 150 days after compliance date.
63.9(i)	Adjustment to time periods or postmark deadlines for submittal and review of required communications	Yes	
63.9(j)	Change in information provided	No	Subpart GGG specifies procedures for notification of changes.
63.10(a)	Recordkeeping requirements	Yes	
63.1259.			
63.10(b)(1)	Records retention	Yes	Also stated in §63.1259.
63.10(b)(2)	Information and documentation to support notifications	No	Subpart GGG specifies recordkeeping requirements.
63.10(b)(3)	Records retention for sources not subject to relevant standard	Yes	Also stated in §63.1259 (a)(2).
63.10(c)(1)-(9)	Additional recordkeeping requirements for sources with continuous monitoring systems	Yes.	
63.10(c)(10)	Malfunction recordkeeping requirement	No	Subpart GGG specifies recordkeeping requirements.
63.10(c)(11)	Malfunction corrective action recordkeeping requirement	No	Subpart GGG specifies recordkeeping requirements.
63.10(c)(12)-(14)	Additional recordkeeping requirements for sources with continuous monitoring systems	Yes.	
63.10(c)(15)	Additional SSM recordkeeping requirements	No.	
63.10(d)(1)-(2)	General reporting requirements	Yes.	
63.10(d)(3)	Reporting results of opacity or visible emissions observations	No	Subpart GGG does not include any opacity or visible emission standards.
63.10(d)(4)	Progress report requirements	Yes.	
63.10(d)(5)	Startup, shutdown, and malfunction report requirements	No	Subpart GGG specifies reporting requirements.
63.10(e)	Additional CMS reporting requirements	Yes	
63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes	
63.11	Control device and equipment leak	Yes	

	work practice requirements		
63.13	Addresses of State air pollution control agencies	Yes	
63.14	Incorporations by reference	Yes	
63.15	Availability of information and confidentiality	Yes	

[63 FR 50326, Sept. 21, 1998, as amended at 65 FR 52614, Aug. 29, 2000; 66 FR 40136, Aug. 2, 2001; 73 FR 78213, Dec. 22, 2008; 76 FR 22601, Apr. 21, 2011]

Table 2 to Subpart GGG of Part 63—Partially Soluble HAP

1,1,1-Trichloroethane (methyl chloroform)	Chloroform
1,1,2,2-Tetrachloroethane	Chloromethane
1,1,2-Trichloroethane	Chloroprene
1,1-Dichloroethylene (vinylidene chloride)	Cumene
1,2-Dibromoethane	Dichloroethyl ether
1,2-Dichloroethane (ethylene dichloride)	Dinitrophenol
1,2-Dichloropropane	Epichlorohydrin
1,3-Dichloropropene	Ethyl acrylate
2,4,5-Trichlorophenol	Ethylbenzene
2-Butanone (mek)	Ethylene oxide
1,4-Dichlorobenzene	Hexachlorobenzene
2-Nitropropane	Hexachlorobutadiene
4-Methyl-2-pentanone (MIBK)	Hexachloroethane
Acetaldehyde	Methyl methacrylate
Acrolein	Methyl-t-butyl ether
Acrylonitrile	Methylene chloride
Allyl chloride	N,N-dimethylaniline
Benzene	Propionaldehyde
Benzyl chloride	Propylene oxide
Biphenyl	Styrene
Bromoform (tribromomethane)	Tetrachloroethene (perchloroethylene)
Bromomethane	Tetrachloromethane (carbon tetrachloride)
Butadiene	Toluene
Carbon disulfide	Trichlorobenzene (1,2,4-)
Chlorobenzene	Trichloroethylene
Chloroethane (ethyl chloride)	Trimethylpentane

Vinyl acetate	Xylene (p)
Vinyl chloride	N-hexane
Xylene (m)	
Xylene (o)	

[66 FR 40136, Aug. 2, 2001]

Table 3 to Subpart GGG of Part 63—Soluble HAP

Compound
1,1-Dimethylhydrazine.
1,4-Dioxane.
Acetonitrile.
Acetophenone.
Diethyl sulfate.
Dimethyl sulfate.
Dinitrotoluene.
Ethylene glycol dimethyl ether.
Ethylene glycol monobutyl ether acetate.
Ethylene glycol monomethyl ether acetate.
Isophorone.
Methanol (methyl alcohol).
Nitrobenzene.
Toluidene.
Triethylamine.

[66 FR 40137, Aug. 2, 2001]

Table 4 to Subpart GGG of Part 63—Monitoring Requirements for Control Devicesa

Control device	Monitoring equipment required	Parameters to be monitored	Frequency
All control devices	1. Flow indicator installed at all bypass lines to the atmosphere and equipped with continuous recorder <i>or</i>	1. Presence of flow diverted from the control device to the atmosphere <i>or</i>	Hourly records of whether the flow indicator was operating and whether a diversion was detected at any time during each hour.

	2. Valves sealed closed with car-seal or lock-and-key configuration	2. Monthly inspections of sealed valves	Monthly.
Scrubber	Liquid flow rate or pressure drop mounting device. Also a pH monitor if the scrubber is used to control acid emissions	1. Liquid flow rate into or out of the scrubber or the pressure drop across the scrubber	1. Every 15 minutes.
		2. pH of effluent scrubber liquid	2. Once a day.
Thermal incinerator	Temperature monitoring device installed in firebox or in ductwork immediately downstream of firebox ^b	Firebox temperature	Every 15 minutes.
Catalytic incinerator	Temperature monitoring device installed in gas stream immediately before and after catalyst bed	Temperature difference across catalyst bed	Every 15 minutes.
Flare	Heat sensing device installed at the pilot light	Presence of a flame at the pilot light	Every 15 minutes.
Boiler or process heater <44 mega watts and vent stream is not mixed with the primary fuel	Temperature monitoring device installed in firebox ^b	Combustion temperature	Every 15 minutes.
Condenser	Temperature monitoring device installed at condenser exit	Condenser exit (product side) temperature	Every 15 minutes.
Carbon adsorber (nonregenerative)	None	Operating time since last replacement	N/A.
Carbon adsorber (regenerative)	Stream flow monitoring device, <i>and</i>	1. Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s)	1. For each regeneration cycle, record the total regeneration stream mass or volumetric flow.
	Carbon bed temperature monitoring device	2. Temperature of carbon bed after regeneration	2. For each regeneration cycle, record the maximum carbon bed-temperature.

		3. Temperature of carbon bed within 15 minutes of completing any cooling cycle(s)	3. Within 15 minutes of completing any cooling cycle, record the carbon bed temperature.
		4. Operating time since end of last regeneration	4. Operating time to be based on worst-case conditions.
		5. Check for bed poisoning	5. Yearly.

^aAs an alternative to the monitoring requirements specified in this table, the owner or operator may use a CEM meeting the requirements of Performance Specifications 8 or 9 of appendix B of part 60 to monitor TOC every 15 minutes.

^bMonitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

Table 5 to Subpart GGG of Part 63—Control Requirements for Items of Equipment That Meet the Criteria of §63.1252(f)

Item of equipment	Control requirement^a
Drain or drain hub	(a) Tightly fitting solid cover (TFSC); or
	(b) TFSC with a vent to either a process or to a control device meeting the requirements of §63.1256(h)(2); or
	(c) Water seal with submerged discharge or barrier to protect discharge from wind.
Manhole ^b	(a) TFSC; or
	(b) TSFC with a vent to either a process or to a control device meeting the requirements of §63.1256(h)(2); or
	(c) If the item is vented to the atmosphere, use a TFSC with a properly operating water seal at the entrance or exit to the item to restrict ventilation in the collection system. The vent pipe shall be at least 90 cm in length and not exceeding 10.2 cm in nominal inside diameter.
Lift station	(a) TFSC; or
	(b) TFSC with a vent to either a process or to a control device meeting the requirements of §63.1256(h)(2); or
	(c) If the lift station is vented to the atmosphere, use a TFSC with a properly operating water seal at the entrance or exit to the item to restrict ventilation in the

	collection system. The vent pipe shall be at least 90 cm in length and not exceeding 10.2 cm in nominal inside diameter. The lift station shall be level controlled to minimize changes in the liquid level.
Trench	(a) TFSC; or
	(b) TFSC with a vent to either a process or to a control device meeting the requirements of §63.1256(h)(2); or
	(c) If the item is vented to the atmosphere, use a TFSC with a properly operating water seal at the entrance or exit to the item to restrict ventilation in the collection system. The vent pipe shall be at least 90 cm in length and not exceeding 10.2 cm in nominal inside diameter.
Pipe	Each pipe shall have no visible gaps in joints, seals, or other emission interfaces.
Oil/Water separator	(a) Equip with a fixed roof and route vapors to a process or equip with a closed-vent system that routes vapors to a control device meeting the requirements of §63.1256(h)(2); or
	(b) Equip with a floating roof that meets the equipment specifications of §60.693(a)(1)(i), (a)(1)(ii), (a)(2), (a)(3), and (a)(4).
Tank	Maintain a fixed roof and consider vents as process vents. ^c

^aWhere a tightly fitting solid cover is required, it shall be maintained with no visible gaps or openings, except during periods of sampling, inspection, or maintenance.

^bManhole includes sumps and other points of access to a conveyance system.

^cA fixed roof may have openings necessary for proper venting of the tank, such as pressure/vacuum vent, j-pipe vent.

[65 FR 52616, Aug. 29, 2000]

Table 6 to Subpart GGG of Part 63—Wastewater— Compliance Options for Wastewater Tanks

Capacity, m ³	Maximum true vapor pressure, kPa	Control requirements
<75		§63.1256(b)(1).
>75 and <151	<13.1	§63.1256(b)(1).
	>13.1	§63.1256(b)(2).
>151	<5.2	§63.1256(b)(1).
	>5.2	§63.1256(b)(2).

**Table 7 to Subpart GGG of Part 63—Wastewater—
Inspection and Monitoring Requirements for Waste
Management Units**

To comply with	Inspection or monitoring requirement	Frequency of inspection or monitoring	Method
TANKS:			
63.1256(b)(3)(i)	Inspect fixed roof and all openings for leaks	Initially Semiannually	Visual.
63.1256(b)(4)	Inspect floating roof in accordance with §§63.120(a)(2) and (a)(3)	See §§63.120(a)(2) and (a)(3)	Visual.
63.1256(b)(5)	Measure floating roof seal gaps in accordance with §§63.120(b)(2)(i) through (b)(4)		See §63.120(b)(2)(i) through (b)(4).
	—Primary seal gaps	Initially Once every 5 years (annually if no secondary seal).	
	—Secondary seal gaps	Initially Semiannually	
63.1256(b)(7) 63.1256(b)(8)	Inspect wastewater tank for control equipment failures and improper work practices	Initially Semiannually	Visual.
SURFACE IMPOUNDMENTS:			
63.1256(c)(1)(i)	Inspect cover and all openings for leaks	Initially Semiannually	Visual.
63.1256(c)(2)	Inspect surface impoundment for control equipment failures and improper work practices	Initially Semiannually	Visual.
CONTAINERS:			
63.1256(d)(1)(i) 63.1256(d)(1)(ii)	Inspect cover and all openings for leaks	Initially Semiannually	Visual.
63.1256(d)(3)(i)	Inspect enclosure and all openings for leaks	Initially Semiannually	Visual.
63.1256(d)(4)	Inspect container for	Initially	Visual.

	control equipment failures and improper work practices	Semiannually	
INDIVIDUAL DRAIN SYSTEMS^a:			
63.1256(e)(1)(i)	Inspect cover and all openings to ensure there are no gaps, cracks, or holes	Initially Semiannually	Visual.
63.1256(e)(2)	Inspect individual drain system for control equipment failures and improper work practices	Initially Semiannually	Visual.
63.1256(e)(4)(i)	Verify that sufficient water is present to properly maintain integrity of water seals	Initially Semiannually	Visual.
63.1256(e)(4)(ii) 63.1256(e)(5)(i)	Inspect all drains using tightly-fitted caps or plugs to ensure caps and plugs are in place and properly installed	Initially Semiannually	Visual.
63.1256(e)(5)(ii)	Inspect all junction boxes to ensure covers are in place and have no visible gaps, cracks, or holes	Initially Semiannually	Visual or smoke test or other means as specified.
63.1256(e)(5)(iii)	Inspect unburied portion of all sewer lines for cracks and gaps	Initially Semiannually	Visual.
OIL-WATER SEPARATORS:			
63.1256(f)(2)(i)	Inspect fixed roof and all openings for leaks	Initially Semiannually	Visual.
63.1256(f)(3)	Measure floating roof seal gaps in accordance with 40 CFR 60.696(d)(1)	Initially ^b	See 40 CFR 60.696(d)(1).
	—Primary seal gaps	Once every 5 years.	
63.1256(f)(3)	—Secondary seal gaps	Initially ^b Annually.	
63.1256(f)(4)	Inspect oil-water separator for control equipment failures and improper work practices	Initially Semiannually	Visual.

^aAs specified in §63.1256(e), the owner or operator shall comply with either the requirements of §63.1256(e)(1) and (2) or §63.1256(e)(4) and (5).

^bWithin 60 days of installation as specified in §63.1256(f)(3).

Table 8 to Subpart GGG of Part 63—Fraction Measured (F_m) for HAP Compounds in Wastewater Streams

Chemical name	CAS No. ^a	F_m
Acetaldehyde	75070	1.00
Acetonitrile	75058	0.99
Acetophenone	98862	0.31
Acrolein	107028	1.00
Acrylonitrile	107131	1.00
Allyl chloride	107051	1.00
Benzene	71432	1.00
Benzyl chloride	100447	1.00
Biphenyl	92524	0.86
Bromoform	75252	1.00
Butadiene (1,3-)	106990	1.00
Carbon disulfide	75150	1.00
Carbon tetrachloride	56235	1.00
Chlorobenzene	108907	0.96
Chloroform	67663	1.00
Chloroprene (2-Chloro-1,3-butadiene)	126998	1.00
Cumene	98828	1.00
Dichlorobenzene (p-1,4-)	106467	1.00
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00
Dichloroethylether (Bis(2-Chloroethyl ether))	111444	0.76
Dichloropropene (1,3-)	542756	1.00
Diethyl sulfate	64675	0.0025
Dimethyl sulfate	77781	0.086
Dimethylaniline (N,N-)	121697	0.00080
Dimethylhydrazine (1,1-)	57147	0.38
Dinitrophenol (2,4-)	51285	0.0077
Dinitrotoluene (2,4-)	121142	0.085
Dioxane (1,4-) (1,4-Diethyleneoxide)	123911	0.87

Epichlorohydrin(1-Chloro-2,3-epoxypropane)	106898	0.94
Ethyl acrylate	140885	1.00
Ethylbenzene	100414	1.00
Ethyl chloride (Chloroethane)	75003	1.00
Ethylene dibromide (Dibromomethane)	106934	1.00
Ethylene glycol dimethyl ether	110714	0.86
Ethylene glycol monobutyl ether acetate	112072	0.043
Ethylene glycol monomethyl ether acetate	110496	0.093
Ethylene oxide	75218	1.00
Ethylidene dichloride (1,1-Dichloroethane)	75343	1.00
Hexachlorobenzene	118741	0.97
Hexachlorobutadiene	87683	0.88
Hexachloroethane	67721	0.50
Hexane	110543	1.00
Isophorone	78591	0.47
Methanol	67561	0.85
Methyl bromide (Bromomethane)	74839	1.00
Methyl chloride (Chloromethane)	74873	1.00
Methyl ethyl ketone (2-Butanone)	78933	0.99
Methyl isobutyl ketone (Hexone)	108101	0.98
Methyl methacrylate	80626	1.00
Methyl tert-butyl ether	1634044	1.00
Methylene chloride (Dichloromethane)	75092	1.00
Naphthalene	91203	0.99
Nitrobenzene	98953	0.39
Nitropropane (2-)	79469	0.99
Phosgene	75445	1.00
Propionaldehyde	123386	1.00
Propylene dichloride (1,2-Dichloropropane)	78875	1.00
Propylene oxide	75569	1.00
Styrene	100425	1.00
Tetrachloroethane (1,1,2,2-)	79345	1.00
Tetrachloroethylene (Perchloroethylene)	127184	1.00
Toluene	108883	1.00
Toluidine (o-)	95534	0.15
Trichlorobenzene (1,2,4-)	120821	1.00

Trichloroethane (1,1,1-) (Methyl chloroform)	71556	1.00
Trichloroethane (1,1,2-) (Vinyl Trichloride)	79005	0.98
Trichloroethylene	79016	1.00
Trichlorophenol (2,4,5-)	95954	1.00
Triethylamine	121448	1.00
Trimethylpentane (2,2,4-)	540841	1.00
Vinyl acetate	108054	1.00
Vinyl chloride (Chloroethylene)	75014	1.00
Vinylidene chloride (1,1-Dichloroethylene)	75354	1.00
Xylene (m-)	108383	1.00
Xylene (o-)	95476	1.00
Xylene (p-)	106423	1.00

^aCAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

Table 9 to Subpart GGG of Part 63—Default Biorates for Soluble HAP

Compound name	Biorate (K1), L/g MLVSS-hr
Acetonitrile	0.100
Acetophenone	0.538
Diethyl sulfate	0.105
Dimethyl hydrazine(1,1)	0.227
Dimethyl sulfate	0.178
Dinitrotoluene(2,4)	0.784
Dioxane(1,4)	0.393
Ethylene glycol dimethyl ether	0.364
Ethylene glycol monobutyl ether acetate	0.496
Ethylene glycol monomethyl ether acetate	0.159
Isophorone	0.598
Methanol	^a
Nitrobenzene	2.300
Toluidine (-0)	0.859
Triethylamine	1.064

^aFor direct dischargers, the default biorate for methanol is 3.5 L/g MLVSS-hr; for indirect dischargers, the default biorate for methanol is 0.2 L/g MLVSS-hr.

[66 FR 40137, Aug. 2, 2001]

Appendix K

§ 60.4200

40 CFR Ch. I (7–1–14 Edition)

Report	Due date	Contents	Reference
4. Emission limitation or operating limit deviation report.	a. By August 1 of that year for data collected during the first half of the calendar year. By February 1 of the following year for data collected during the second half of the calendar year	x. Documentation of periods when all qualified OSWI unit operators were unavailable for more than 12 hours but less than 2 weeks. i. Dates and times of deviation;.	§§ 60.3050 and 60.3051. §§ 60.3052 and 60.3053.
		ii. Averaged and recorded data for those dates;.	§§ 60.3052 and 60.3053.
		iii. Duration and causes of each deviation and the corrective actions taken..	§§ 60.3052 and 60.3053.
		iv. Copy of operating limit monitoring data and any test reports;.	§§ 60.3052 and 60.3053.
		v. Dates, times, and causes for monitor downtime incidents;.	§§ 60.3052 and 60.3053.
		vi. Whether each deviation occurred during a period of startup, shutdown, or malfunction; and.	§§ 60.3052 and 60.3053.
		vii. Dates, times, and duration of any bypass of the control device.	§§ 60.3052 and 60.3053.
5. Qualified operator deviation notification.	a. Within 10 days of deviation	i. Statement of cause of deviation;.	§ 60.3054(a)(1).
		ii. Description of efforts to have an accessible qualified operator; and.	§ 60.3054(a)(1).
		iii. The date a qualified operator will be accessible.	§ 60.3054(a)(1).
6. Qualified operation deviation status report.	a. Every 4 weeks following deviation	i. Description of efforts to have an accessible qualified operator;.	§ 60.3054(a)(2).
		ii. The date a qualified operator will be accessible; and.	§ 60.3054(a)(2).
		iii. Request to continue operation.	§ 60.3054(a)(2).
7. Qualified operator deviation notification of resumed operation.	a. Prior to resuming operation	i. Notification that you are resuming operation.	§ 60.3054(b).

Note: This table is only a summary, see the referenced sections of the rule for the complete requirements.

[70 FR 74907, Dec. 16, 2005, as amended at 71 FR 67806, Nov. 24, 2006]

Subparts GGGG–HHHH [Reserved]

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners,

and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

Environmental Protection Agency

§ 60.4201

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine

under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

EMISSION STANDARDS FOR MANUFACTURERS

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification

emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are

not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards

and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4203

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

EMISSION STANDARDS FOR OWNERS AND OPERATORS

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

40 CFR Ch. I (7–1–14 Edition)

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

FUEL REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-

emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

COMPLIANCE REQUIREMENTS

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in § 60.4201(a) through (c) and § 60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later

standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in § 60.4201(d) and (e) and § 60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do

not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner’s manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§ 60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must

comply with the emission standards specified in §§ 60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_x and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_x and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or

§ 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance

company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads

that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and

§ 60.4212

must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

40 CFR Ch. I (7–1–14 Edition)

TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad (\text{Eq. 1})$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing

Environmental Protection Agency

§ 60.4213

procedures specified in § 60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in

§ 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 2})$$

Where:

C_i = concentration of NO_x or PM at the control device inlet,

C_o = concentration of NO_x or PM at the control device outlet, and

R = percent reduction of NO_x or PM emissions.

(2) You must normalize the NO_x or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O₂) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO₂) using the procedures described in paragraph (d)(3) of this section.

$$C_{\text{adj}} = C_d \frac{5.9}{20.9 - \% \text{ O}_2} \quad (\text{Eq. 3})$$

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O₂.

C_d = Measured concentration of NO_x or PM, uncorrected.

5.9 = 20.9 percent O₂ – 15 percent O₂, the defined O₂ correction value, percent.

%O₂ = Measured O₂ concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O₂ and CO₂ concentration is measured in lieu of O₂ concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 4})$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2 , percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad (\text{Eq. 5})$$

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq. 7})$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_x concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq. 8})$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

Where:

X_{CO_2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 –15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the NO_x and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (\text{Eq. 6})$$

Where:

C_{adj} = Calculated NO_x or PM concentration adjusted to 15 percent O_2 .

C_d = Measured concentration of NO_x or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 7 of this section:

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

Environmental Protection Agency

§ 60.4214

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15

hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written

§ 60.4215

report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

SPECIAL REQUIREMENTS

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

40 CFR Ch. I (7–1–14 Edition)

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§ 60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in § 60.4202 and § 60.4205, and not those for non-emergency engines in § 60.4201 and § 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in § 60.4201 and § 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in

Environmental Protection Agency

§ 60.4219

areas of Alaska not accessible by the FAHS.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

GENERAL PROVISIONS

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

DEFINITIONS

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning

given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine

block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is

used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other nonstationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine

Environmental Protection Agency

Pt. 60, Subpt. IIII, Table 2

which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

TABLE 1 TO SUBPART IIII OF PART 60—EMISSION STANDARDS FOR STATIONARY PRE-2007 MODEL YEAR ENGINES WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER AND 2007–2010 MODEL YEAR ENGINES >2,237 KW (3,000 HP) AND WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO _x	HC	NO _x	CO	PM
KW<8 (HP<11)	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	9.2 (6.9)
56≤KW<75 (75≤HP<100)	9.2 (6.9)
75≤KW<130 (100≤HP<175)	9.2 (6.9)
130≤KW<225 (175≤HP<300)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

TABLE 2 TO SUBPART IIII OF PART 60—EMISSION STANDARDS FOR 2008 MODEL YEAR AND LATER EMERGENCY STATIONARY CI ICE <37 KW (50 HP) WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO _x + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Pt. 60, Subpt. IIII, Table 3

40 CFR Ch. I (7–1–14 Edition)

TABLE 3 TO SUBPART IIII OF PART 60—CERTIFICATION REQUIREMENTS FOR STATIONARY FIRE PUMP ENGINES

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d) ¹	Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d) ¹
KW<75 (HP<100)	2011	KW>560 (HP>750)	2008
75≤KW<130 (100≤HP<175)	2010	¹ Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 kW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.	
130≤KW≤560 (175≤HP≤750)	2009		

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

TABLE 4 TO SUBPART IIII OF PART 60—EMISSION STANDARDS FOR STATIONARY FIRE PUMP ENGINES

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO _x	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ ¹	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+ ¹	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+ ²	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ ³	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+ ³	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

¹For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.²For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.³In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

TABLE 5 TO SUBPART IIII OF PART 60—LABELING AND RECORDKEEPING REQUIREMENTS FOR NEW STATIONARY EMERGENCY ENGINES

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Environmental Protection Agency

Pt. 60, Subpt. IIII, Table 7

TABLE 6 TO SUBPART IIII OF PART 60—OPTIONAL 3-MODE TEST CYCLE FOR STATIONARY FIRE PUMP ENGINES

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed ¹	Torque (percent) ²	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

¹ Engine speed: ± 2 percent of point.

² Torque: NFPA certified nameplate HP for 100 percent point. All points should be ± 2 percent of engine percent load value.

TABLE 7 TO SUBPART IIII OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥ 30 LITERS PER CYLINDER

As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥ 30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder.	a. Reduce NO _x emissions by 90 percent or more;.	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;.		(a) For NO _x , O ₂ , and moisture measurement, ducts ≤ 6 inches in diameter may be sampled at a single point located at the duct centroid and ducts > 6 and ≤ 12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is > 12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O ₂ at the inlet and outlet of the control device;.	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2.	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for NO _x concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO _x concentration.

Pt. 60, Subpt. IIII, Table 7

40 CFR Ch. I (7–1–14 Edition)

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO _x in the stationary CI internal combustion engine exhaust..	<p>iv. Measure NO_x at the inlet and outlet of the control device..</p> <p>i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;.</p>	<p>(3) Method 7E of 40 CFR part 60, appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).</p>	<p>(d) NO_x concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p> <p>(a) For NO_x, O₂, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A–4.</p>
		<p>ii. Determine the O₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;.</p> <p>iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and</p>	<p>(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2.</p> <p>(2) Method 4 of 40 CFR part 60, appendix A–3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).</p>	<p>(b) Measurements to determine O₂ concentration must be made at the same time as the measurement for NO_x concentration.</p> <p>(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_x concentration.</p>
	c. Reduce PM emissions by 60 percent or more.	<p>iv. Measure NO_x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device..</p> <p>i. Select the sampling port location and the number of traverse points;.</p>	<p>(3) Method 7E of 40 CFR part 60, Appendix A–4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).</p> <p>(1) Method 1 or 1A of 40 CFR part 60, appendix A–1.</p>	<p>(d) NO_x concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p> <p>(a) Sampling sites must be located at the inlet and outlet of the control device.</p>

Environmental Protection Agency

Pt. 60, Subpt. IIII, Table 8

Each	Complying with the requirement to	You must	Using	According to the following requirements
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust.	<p>ii. Measure O₂ at the inlet and outlet of the control device;.</p> <p>iii. If necessary, measure moisture content at the inlet and outlet of the control device; and</p> <p>iv. Measure PM at the inlet and outlet of the control device..</p> <p>i. Select the sampling port location and the number of traverse points;.</p> <p>ii. Determine the O₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;.</p> <p>iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and</p> <p>iv. Measure PM at the exhaust of the stationary internal combustion engine..</p>	<p>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2.</p> <p>(3) Method 4 of 40 CFR part 60, appendix A–3.</p> <p>(4) Method 5 of 40 CFR part 60, appendix A–3.</p> <p>(1) Method 1 or 1A of 40 CFR part 60, appendix A–1.</p> <p>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A–2.</p> <p>(3) Method 4 of 40 CFR part 60, appendix A–3.</p> <p>(4) Method 5 of 40 CFR part 60, appendix A–3.</p>	<p>(b) Measurements to determine O₂ concentration must be made at the same time as the measurements for PM concentration.</p> <p>(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.</p> <p>(d) PM concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p> <p>(a) If using a control device, the sampling site must be located at the outlet of the control device.</p> <p>(b) Measurements to determine O₂ concentration must be made at the same time as the measurements for PM concentration.</p> <p>(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.</p> <p>(d) PM concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p>

[79 FR 11251, Feb. 27, 2014]

TABLE 8 TO SUBPART IIII OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions.	Yes.	Additional terms defined in § 60.4219.
§ 60.2	Definitions	Yes	
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.7	Notification and Recordkeeping	Yes	

§ 60.4230

40 CFR Ch. I (7–1–14 Edition)

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes.	Requirements are specified in subpart IIII.
§ 60.10	State Authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	
§ 60.12	Circumvention	Yes.	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.13	Monitoring requirements	Yes	
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes.	

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

SOURCE: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

- (i) On or after July 1, 2008; or
- (ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

Appendix L

§ 61.306

within 90 days after the effective date of this subpart or 90 days after startup for a source that has an initial startup date after the effective date.

(1) Periods of operation where there were exceedances of monitored parameters recorded under § 61.305(b).

(2) All periods recorded under § 61.305(c)(1) when the vent stream is diverted from the control device.

(3) All periods recorded under § 61.305(d) when the steam generating unit or process heater was not operating.

(4) All periods recorded under § 61.305(e) in which the pilot flame of the flare was absent.

(5) All times recorded under § 61.305(c)(2) when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed.

(g) The owner or operator of an affected facility shall keep the vapor-tightness documentation required under § 61.302 (d) and (e) on file at the affected facility in a permanent form available for inspection.

(h) The owner or operator of an affected facility shall update the documentation file required under § 61.302 (d) and (e) for each tank truck, railcar, or marine vessel at least once per year to reflect current test results as determined by the appropriate method. The owner or operator shall include, as a minimum, the following information in this documentation:

- (1) Test title;
- (2) Tank truck, railcar, or marine vessel owner and address;
- (3) Tank truck, railcar, or marine vessel identification number;
- (4) Testing location;
- (5) Date of test;
- (6) Tester name and signature;
- (7) Witnessing inspector: name, signature, and affiliation; and
- (8) Test results, including, for railcars and tank trucks, the initial pressure up to which the tank was pressurized at the start of the test.

(i) Each owner or operator of an affected facility complying with § 61.300(b) or § 61.300(d) shall record the following information. The first year after promulgation the owner or operator shall submit a report containing the requested information to the Direc-

40 CFR Ch. I (7–1–14 Edition)

tor of the Emission Standards Division, (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. After the first year, the owner or operator shall continue to record; however, no reporting is required. The information shall be made available if requested. The information shall include, as a minimum:

(1) The affected facility's name and address;

(2) The weight percent of the benzene loaded;

(3) The type of vessel loaded (i.e., tank truck, railcar, or marine vessel); and

(4) The annual amount of benzene loaded into each type of vessel.

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§ 61.306 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: No restrictions.

Subparts CC–EE [Reserved]

Subpart FF—National Emission Standard for Benzene Waste Operations

SOURCE: 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

§ 61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from

Environmental Protection Agency

§ 61.341

any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in § 61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.341 Definitions.

Benzene concentration means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in § 61.355 of this subpart.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Chemical manufacturing plant means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, ben-

zene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alkylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

Coke by-product recovery plant means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

Container means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Cover means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

External floating roof means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

Facility means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

Fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does

not move with fluctuations in liquid level.

Floating roof means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

Flow indicator means a device which indicates whether gas flow is present in a line or vent system.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

Individual drain system means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

Internal floating roof means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

Liquid-mounted seal means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

Loading means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

Maximum organic vapor pressure means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at

the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

- (1) In accordance with §60.17(c); or
- (2) As obtained from standard reference texts; or
- (3) In accordance with §60.17(a)(37); or
- (4) Any other method approved by the Administrator.

No detectable emissions means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in §61.355(h) of this subpart.

Oil-water separator means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator include an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Point of waste generation means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

Process unit means equipment assembled and connected by pipes or ducts to

produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Process unit turnaround means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by re-starting of the process.

Process unit turnaround waste means a waste that is generated as a result of a process unit turnaround.

Process wastewater means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

Process wastewater stream means a waste stream that contains only process wastewater.

Product tank means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Product tank drawdown means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open

only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

Segregated stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

Sewer line means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Sour water stream means a stream that:

- (1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;
- (2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

- (3) Requires treatment to remove the ammonia or sulfur compounds.

Sour water stripper means a unit that:

- (1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

- (2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

- (3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

Surface impoundment means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is

not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Treatment process means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

Vapor-mounted seal means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

Waste means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

Waste management unit means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

Waste stream means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

Wastewater treatment system means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product

tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in § 61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under § 61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under § 61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under § 61.10(b)(3) that is an enforceable commitment to obtain environmental ben-

efits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in § 61.348 of this subpart.

(ii) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§ 61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or

product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of

this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in § 61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

§ 61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in § 61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance

with § 61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with

the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m³ (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m³ (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in §61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

Environmental Protection Agency

§ 61.345

(4) The closed-vent system must be designed and operated in accordance with the requirements of § 61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

§ 61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods

specified in § 61.355(h) of this subpart; and

(3) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

§ 61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with

the criteria for a permanent total enclosure as specified in section 5 of the “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings (e.g., doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

§ 61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste

sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

§ 61.347

40 CFR Ch. I (7–1–14 Edition)

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as

soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

§ 61.347 Standards: Oil-water separators.

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(1) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(2) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(3) The pressure is monitored continuously to ensure that the pressure

in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

§ 61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§ 61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with § 61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in para-

graph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to § 61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with § 61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§ 61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in § 61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams

managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in § 61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in

compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401–464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as

soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in § 61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in § 61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§ 61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device

in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(1) The critical operating parameters that affect the emission control performance of the device;

(2) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(3) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified

in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subject to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

Environmental Protection Agency

§ 61.353

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

§ 61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b(a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

§ 61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693-2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

§ 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only

§ 61.354

40 CFR Ch. I (7–1–14 Edition)

after public notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

§ 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$ or ± 0.5 $^{\circ}\text{C}$, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$ or ± 0.5 $^{\circ}\text{C}$, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW (150×10^6 BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$

or ± 0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150×10^6 BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ± 1 percent of the temperature being monitored in °C or ± 0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of § 61.349(a)(2)(iv), devices to monitor the parameters as specified in § 61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under § 61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by § 61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is

§ 61.355

40 CFR Ch. I (7–1–14 Edition)

maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10

Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in § 61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from off-site shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good

engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§ 61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(I) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is

made through hard piping or other enclosed system.

(2) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability

and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at

a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^n (Q_i)(C_i)$$

Where:

\bar{C} =Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t =Total annual waste quantity for waste stream, kg/yr (lb/yr).

n =Number of waste samples (at least 3).

Q_i =Annual waste quantity for waste stream represented by C_i , kg/yr (lb/yr).

C_i =Measured concentration of benzene in waste sample i , ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste entering the treatment process during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste exiting the treatment process during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^n V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

K = Density of the waste stream, kg/m³ (lb/ft³).

V_i = Average volume flow rate of waste entering the combustion unit during each run i , m³/hr (ft³/hr).

C_i = Average concentration of benzene in the waste stream entering the combustion unit during each run i , ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b VC(10^{-6})$$

Where:

M_i = Mass of benzene emitted during run i , kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, m³ (ft³).

C = Concentration of benzene measured in the exhaust, ppmv.

D_b = Density of benzene, 3.24 kg/m³ (0.202 lb/ft³).

10^6 = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left(\sum_{i=1}^n M_i \right) / T$$

Where:

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

M_i = Mass of benzene emitted from the combustion unit during run i , kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with § 61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§ 61.343 through 61.347, and § 61.349 of

§ 61.355

40 CFR Ch. I (7–1–14 Edition)

this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

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

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which

at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6} \left(\sum_{i=1}^n C_{ai} MW_i \right)$$

$$M_{bj} = \frac{K_1 V_{bj}}{10^6} \left(\sum_{i=1}^n C_{bi} MW_i \right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m³ (ft³).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m³ (ft³).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

Environmental Protection Agency

§ 61.355

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

K₁ = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/m³ (0.00118 lb-mol/ft³)

10⁻⁶=Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a - \left(\sum_{j=1}^n M_{aj} \right) / T$$

$$E_b - \left(\sum_{j=1}^n M_{bj} \right) / T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also

apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with §61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by §61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with §61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and

(k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and

(k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).

(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or

not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(2) For each waste stream exempt from § 61.342(c)(1) in accordance with § 61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with § 61.342(c)(3)(i), or

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with § 61.342(c)(3)(ii).

(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with § 61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with § 61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with § 61.355(a)(1)(iii) of this section.

(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with § 61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with § 61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§ 61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with § 61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain

the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with § 61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with § 61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.

(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.

(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene 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.

(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of

the control device and source operating schedule.

(H) For a control device subject to the requirements of § 61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under § 61.349 (a)(2)(iv).

(ii) [Reserved]

(3) If performance tests are used to determine control device performance in accordance with § 61.349(c) of this subpart:

(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.

(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.

(iv) All test results.

(g) An owner or operator shall maintain a record for each visual inspection required by §§ 61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§ 61.343

through 61.347 and § 61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with § 61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with § 61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(4) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under § 61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.

(ii) The flow monitoring devices required under § 61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(4) If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature.

(5) If a catalytic vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.

(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by

§ 61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150×106 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150×106 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of § 61.354(c)(5).

(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.

(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with § 61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the con-

centration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in § 61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of § 61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693–2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693–2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in §61.343 or the control requirements for containers in §61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

§61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to §61.342 and is determined by the procedures specified in §61.355(c) to contain benzene. Each owner or oper-

ator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with §61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in §61.10(a).

(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever

there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under § 61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under § 61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in

the following year, the owner or operator may submit a statement to that effect.

(3) If an owner or operator elects to comply with the requirements of § 61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.

(4) If an owner or operator elects to comply with the alternative requirements of § 61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:

(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;

(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(5) If an owner or operator elects to comply with the alternative requirements of § 61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information

for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the applicable location described in §61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the

unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.

(iv) For a control device monitored in accordance with §61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

(A) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference.

(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10⁶ BTU/hr), as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature,

or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(F) Each period in which the pilot flame of a flare is absent.

(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by § 61.349(a)(2)(i)(C) of this subpart.

(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in § 61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of § 61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with § 61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Ad-

ministrator a report that summarizes all inspections required by §§ 61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzene emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§ 61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under § 61.07 or § 61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693-2(a), that are outside the prescribed limits.

[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

§ 61.358 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Alternative means of emission limitation under § 61.353 of this subpart will not be delegated to States.

§ 61.359 [Reserved]

Appendix M

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

Contents

[§63.420 Applicability.](#)

[§63.421 Definitions.](#)

[§63.422 Standards: Loading racks.](#)

[§63.423 Standards: Storage vessels.](#)

[§63.424 Standards: Equipment leaks.](#)

[§63.425 Test methods and procedures.](#)

[§63.426 Alternative means of emission limitation.](#)

[§63.427 Continuous monitoring.](#)

[§63.428 Reporting and recordkeeping.](#)

[§63.429 Implementation and enforcement.](#)

[Table 1 to Subpart R of Part 63—General Provisions Applicability to Subpart R](#)

SOURCE: 59 FR 64318, Dec. 14, 1994, unless otherwise noted.

[↑ Back to Top](#)

§63.420 Applicability.

(a) The affected source to which the provisions of this subpart apply is each bulk gasoline terminal, except those bulk gasoline terminals:

(1) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_T , of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$$E_T = CF[0.59(T_F)(1-CE) + 0.17(T_E) + 0.08(T_{ES}) + 0.038(T_I) + 8.5 \times 10^{-6}(C) + KQ] + 0.04(OE)$$

where:

E_T = emissions screening factor for bulk gasoline terminals;

CF = 0.161 for bulk gasoline terminals and pipeline breakout stations that do not handle any reformulated or oxygenated gasoline containing 7.6 percent by volume or greater methyl tert-butyl ether (MTBE), OR

CF = 1.0 for bulk gasoline terminals and pipeline breakout stations that handle reformulated or oxygenated gasoline containing 7.6 percent by volume or greater MTBE;

CE = control efficiency limitation on potential to emit for the vapor processing system used to control emissions from fixed-roof gasoline storage vessels [value should be added in decimal form (percent divided by 100)];

T_F = total number of fixed-roof gasoline storage vessels without an internal floating roof;

T_E = total number of external floating roof gasoline storage vessels with only primary seals;

T_{ES} = total number of external floating roof gasoline storage vessels with primary and secondary seals;

T_I = total number of fixed-roof gasoline storage vessels with an internal floating roof;

C = number of valves, pumps, connectors, loading arm valves, and open-ended lines in gasoline service;

Q = gasoline throughput limitation on potential to emit or gasoline throughput limit in compliance with paragraphs (c), (d), and (f) of this section (liters/day);

$K = 4.52 \times 10^{-6}$ for bulk gasoline terminals with uncontrolled loading racks (no vapor collection and processing systems), *OR*

$K = (4.5 \times 10^{-9})(EF + L)$ for bulk gasoline terminals with controlled loading racks (loading racks that have vapor collection and processing systems installed on the emission stream);

EF = emission rate limitation on potential to emit for the gasoline cargo tank loading rack vapor processor outlet emissions (mg of total organic compounds per liter of gasoline loaded);

OE = other HAP emissions screening factor for bulk gasoline terminals or pipeline breakout stations (tons per year). OE equals the total HAP from other emission sources not specified in parameters in the equations for E_T or E_P . If the value of $0.04(OE)$ is greater than 5 percent of either E_T or E_P , then paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability;

L = 13 mg/l for gasoline cargo tanks meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in §60.501 of this chapter, *OR*

L = 304 mg/l for gasoline cargo tanks not meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in §60.501 of this chapter; or

(2) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in §63.2 of subpart A of this part.

(b) The affected source to which the provisions of this subpart apply is each pipeline breakout station, except those pipeline breakout stations:

(1) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_p , of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$$E_p = CF [6.7(T_F)(1-CE) + 0.21(T_E) + 0.093(T_{ES}) + 0.1(T_I) + 5.31 \times 10^{-6}(C)] + 0.04(OE);$$

where:

E_p = emissions screening factor for pipeline breakout stations,

and the definitions for CF, T_F , CE, T_E , T_{ES} , T_I , C, and OE are the same as provided in paragraph (a)(1) of this section; or

(2) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in §63.2 of subpart A of this part.

(c) A facility for which the results, E_T or E_p , of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 1.0 but greater than or equal to 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section, and approved by the Administrator, is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of §63.428(i).

(d) A facility for which the results, E_T or E_p , of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of §63.428(j).

(e) The provisions of paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability to bulk gasoline terminals or pipeline breakout stations that are either:

(1) Located within a contiguous area and under common control with another bulk gasoline terminal or pipeline breakout station, or

(2) Located within a contiguous area and under common control with other sources not specified in paragraphs (a)(1) or (b)(1) of this section, that emit or have the potential to emit a hazardous air pollutant.

(f) Upon request by the Administrator, the owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of any paragraphs in this section including, but not limited to, the parameters and assumptions used in the applicable equation in paragraph (a)(1) or (b)(1) of this section, shall demonstrate compliance with those paragraphs.

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of 40 CFR part 60, subpart Kb or XX of this chapter shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility.

(h) Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station is subject to the provisions of 40 CFR part 63, subpart A—General Provisions, as indicated in Table 1.

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with subpart CC, §§63.646, 63.648, 63.649, and 63.650 is not subject to subpart R standards, except as specified in subpart CC, §63.650.

(j) *Rules stayed for reconsideration.* Notwithstanding any other provision of this subpart, the December 14, 1995 compliance date for existing facilities in §63.424(e) and §63.428(a), (i)(1), and (j)(1) of this subpart is stayed from December 8, 1995, to March 7, 1996.

[59 FR 64318, Dec. 14, 1994, as amended at 60 FR 43260, Aug. 18, 1995; 60 FR 62992, Dec. 8, 1995; 62 FR 9092, Feb. 28, 1997]

[↑ Back to Top](#)

§63.421 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act; in subparts A, K, Ka, Kb, and XX of part 60 of this chapter; or in subpart A of this part. All terms defined in both subpart A of part 60 of this chapter and subpart A of this part shall have the meaning given in subpart A of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Bulk gasoline terminal means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.

Controlled loading rack, for the purposes of §63.420, means a loading rack equipped with vapor collection and processing systems that reduce displaced vapor emissions to no more than 80 milligrams of total organic compounds per liter of gasoline loaded, as measured using the test methods and procedures in §60.503 (a) through (c) of this chapter.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in the gasoline liquid transfer and vapor collection systems. This definition also includes the entire vapor processing system except the exhaust port(s) or stack(s).

Flare means a thermal oxidation system using an open (without enclosure) flame.

Gasoline cargo tank means a delivery tank truck or railcar which is loading gasoline or which has loaded gasoline on the immediately previous load.

In gasoline service means that a piece of equipment is used in a system that transfers gasoline or gasoline vapors.

Limitation(s) on potential to emit means limitation(s) limiting a source's potential to emit as defined in §63.2 of subpart A of this part.

Operating parameter value means a value for an operating or emission parameter of the vapor processing system (e.g., temperature) which, if maintained continuously by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with the applicable emission standard. The operating parameter value is determined using the procedures outlined in §63.425(b).

Oxygenated gasoline means the same as defined in 40 CFR 80.2(rr).

Pipeline breakout station means a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

Reformulated gasoline means the same as defined in 40 CFR 80.2(ee).

Thermal oxidation system means a combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures.

Uncontrolled loading rack means a loading rack used to load gasoline cargo tanks that is not a controlled loading rack.

Vapor-tight gasoline cargo tank means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in §63.425(e), and which is subject at all times to the test requirements in §63.425 (f), (g), and (h).

Volatile organic liquid (VOL) means, for the purposes of this subpart, gasoline.

[59 FR 64318, Dec. 14, 1994, as amended at 62 FR 9093, Feb. 28, 1997; 68 FR 70965, Dec. 19, 2003]

[↑ Back to Top](#)

§63.422 Standards: Loading racks.

(a) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in §60.502 of this chapter except for paragraphs (b), (c), and (j) of that section. For purposes of this section, the term “affected facility” used in §60.502 of this chapter means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.

(b) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with §60.502(e) of this chapter as follows:

(1) For the purposes of this section, the term “tank truck” as used in §60.502(e) of this chapter means “cargo tank.”

(2) Section 60.502(e)(5) of this chapter is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(i) The tank truck or railcar gasoline cargo tank meets the test requirements in §63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in §63.425(i);

(ii) For each gasoline cargo tank failing the test in §63.425 (f) or (g) at the facility, the cargo tank either:

(A) Before repair work is performed on the cargo tank, meets the test requirements in §63.425 (g) or (h), or

(B) After repair work is performed on the cargo tank before or during the tests in §63.425 (g) or (h), subsequently passes the annual certification test described in §63.425(e).

(d) Each owner or operator shall meet the requirements in all paragraphs of this section as expeditiously as practicable, but no later than December 15, 1997, at existing facilities and upon startup for new facilities.

(e) As an alternative to 40 CFR 60.502(h) and (i) as specified in paragraph (a) of this section, the owner or operator may comply with paragraphs (e)(1) and (2) of this section.

(1) The owner or operator shall design and operate the vapor processing system, vapor collection system, and liquid loading equipment to prevent gauge pressure in the railcar gasoline cargo tank from exceeding the applicable test limits in §63.425(e) and (i) during product loading. This level is not to be exceeded when measured by the procedures specified in 40 CFR 60.503(d) of this chapter.

(2) No pressure-vacuum vent in the bulk gasoline terminal's vapor processing system or vapor collection system may begin to open at a system pressure less than the applicable test limits in §63.425(e) or (i).

[59 FR 64318, Dec. 14, 1994; 60 FR 32913, June 26, 1995, as amended at 68 FR 70965, Dec. 19, 2003]

[↑ Back to Top](#)

§63.423 Standards: Storage vessels.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in §60.112b(a) (1) through (4) of this chapter, except for the requirements in §§60.112b(a)(1) (iv) through (ix) and 60.112b(a)(2)(ii) of this chapter.

(b) Each owner or operator shall equip each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in §60.112b(a)(2)(ii) of this chapter if such storage vessel does not currently meet the requirements in paragraph (a) of this section.

(c) Each gasoline storage vessel at existing bulk gasoline terminals and pipeline breakout stations shall be in compliance with the requirements in paragraphs (a) and (b) of this section as expeditiously as practicable, but no later than December 15, 1997. At new bulk gasoline terminals and pipeline breakout stations, compliance shall be achieved upon startup.

[↑ Back to Top](#)

§63.424 Standards: Equipment leaks.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service. For this inspection, detection methods incorporating sight, sound, and smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank.

(b) A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(c) Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (d) of this section.

(d) Delay of repair of leaking equipment will be allowed upon a demonstration to the Administrator that repair within 15 days is not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed.

(e) Initial compliance with the requirements in paragraphs (a) through (d) of this section shall be achieved by existing sources as expeditiously as practicable, but no later than December 15, 1997. For new sources, initial compliance shall be achieved upon startup.

(f) As an alternative to compliance with the provisions in paragraphs (a) through (d) of this section, owners or operators may implement an instrument leak monitoring program that has been demonstrated to the Administrator as at least equivalent.

(g) Owners and operators shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers with a gasketed seal when not in use;

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

[59 FR 64318, Dec. 14, 1994, as amended at 61 FR 7723, Feb. 29, 1996]

[↑ Back to Top](#)

§63.425 Test methods and procedures.

(a) Each owner or operator subject to the emission standard in §63.422(b) or 40 CFR 60.112b(a)(3)(ii) shall comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (a)(1)(i) or (ii) of this section.

(i) Use the test methods and procedures in 40 CFR 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under 40 CFR 60.503(b), or

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(2) The performance test requirements of 40 CFR 60.503(c) do not apply to flares defined in §63.421 and meeting the flare requirements in §63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §63.11(b) and 40 CFR 60.503(a), (b), and (d), respectively.

(b) For each performance test conducted under paragraph (a) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

(1) During the performance test, continuously record the operating parameter under §63.427(a);

(2) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

(3) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in §63.422(b) or §60.112b(a)(3)(ii) of this chapter.

(c) For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test.

(d) The owner or operator of each gasoline storage vessel subject to the provisions of §63.423 shall comply with §60.113b of this chapter. If a closed vent system and control device are used, as specified in §60.112b(a)(3) of this chapter, to comply with the requirements in §63.423, the owner or operator shall also comply with the requirements in paragraph (b) of this section.

(e) *Annual certification test.* The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27, appendix A, 40 CFR part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 mm H₂ O (18 in. H₂ O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H₂ O (6 in. H₂ O), gauge. The maximum allowable pressure and vacuum changes (Δp , Δv) are as shown in the second column of Table 2 of this paragraph.

Table 2—Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change (Δp, Δv) in 5 minutes, mm H₂ O (in. H₂ O)	Allowable pressure change (Δp) in 5 minutes at any time, mm H₂ O (in. H₂ O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

(2) Pressure test of the cargo tank's internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this section, use the procedures in Method 27 to repressurize the tank to 460 mm H₂ O (18 in. H₂ O), gauge. Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

(ii) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H₂ O (5 in. H₂ O).

(f) *Leak detection test.* The leak detection test shall be performed using Method 21, appendix A, 40 CFR part 60, except omit section 4.3.2 of Method 21. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph.

(1) The leak definition shall be 21,000 ppm as propane. Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

(2) In addition to the procedures in Method 21, include the following procedures:

(i) Perform the test on each compartment during loading of that compartment or while the compartment is still under pressure.

(ii) To eliminate a positive instrument drift, the dwell time for each leak detection shall not exceed two times the instrument response time. Purge the instrument with ambient air between each leak detection. The duration of the purge shall be in excess of two instrument response times.

(iii) Attempt to block the wind from the area being monitored. Record the highest detector reading and location for each leak.

(g) *Nitrogen pressure decay field test.* For those cargo tanks with manifolded product lines, this test procedure shall be conducted on each compartment.

(1) Record the cargo tank capacity. Upon completion of the loading operation, record the total volume loaded. Seal the cargo tank vapor collection system at the vapor coupler. The sealing apparatus shall have a pressure tap. Open the internal vapor valve(s) of the cargo tank and record the initial headspace pressure. Reduce or increase, as necessary, the initial headspace pressure to 460 mm H₂ O (18.0 in. H₂ O), gauge by releasing pressure or by adding commercial grade nitrogen gas from a high pressure cylinder capable of maintaining a pressure of 2,000 psig.

(i) The cylinder shall be equipped with a compatible two-stage regulator with a relief valve and a flow control metering valve. The flow rate of the nitrogen shall be no less than 2 cfm. The maximum allowable time to pressurize cargo tanks with headspace volumes of 1,000 gallons or less to the appropriate pressure is 4 minutes. For cargo tanks with a headspace of greater than 1,000 gallons, use as a maximum allowable time to pressurize 4 minutes or the result from the equation below, whichever is greater.

$$T = V_h \times 0.004$$

where:

T = maximum allowable time to pressurize the cargo tank, min;

V_h = cargo tank headspace volume during testing, gal.

(2) It is recommended that after the cargo tank headspace pressure reaches approximately 460 mm H₂ O (18 in. H₂O), gauge, a fine adjust valve be used to adjust the headspace pressure to 460 mm H₂ O (18.0 in. H₂ O), gauge for the next 30 ±5 seconds.

(3) Reseal the cargo tank vapor collection system and record the headspace pressure after 1 minute. The measured headspace pressure after 1 minute shall be greater than the minimum allowable final headspace pressure (P_F) as calculated from the following equation:

$$P_F = 18 \left(\frac{(18 - N)}{18} \right)^{\left(\frac{V_s}{3(V_h)} \right)}$$

[View or download PDF](#)

where:

(P_F) = minimum allowable final headspace pressure, in. H₂ O, gauge;

V_s = total cargo tank shell capacity, gal;

V_h = cargo tank headspace volume after loading, gal;

18.0 = initial pressure at start of test, in. H₂ O, gauge;

N = 5-minute continuous performance standard at any time from the third column of Table 2 of §63.425(e)(i), inches H₂ O.

(4) Conduct the internal vapor valve portion of this test by repressurizing the cargo tank headspace with nitrogen to 460 mm H₂ O (18 in. H₂ O), gauge. Close the internal vapor valve(s), wait for 30 ±5 seconds, then relieve the pressure downstream of the vapor valve in the vapor collection system to atmospheric pressure. Wait 15 seconds, then reseal the vapor collection system. Measure and record the pressure every minute for 5 minutes. Within 5 seconds of the pressure measurement at the end of 5 minutes, open the vapor valve and record the headspace pressure as the “final pressure.”

(5) If the decrease in pressure in the vapor collection system is less than at least one of the interval pressure change values in Table 3 of this paragraph, or if the final pressure is equal to or greater than 20 percent of the 1-minute final headspace pressure determined in the test in paragraph (g)(3) of this section, then the cargo tank is considered to be a vapor-tight gasoline cargo tank.

Table 3—Pressure Change for Internal Vapor Valve Test

Time interval	Interval pressure change, mm H ₂ O (in. H ₂ O)
After 1 minute	28 (1.1)
After 2 minutes	56 (2.2)
After 3 minutes	84 (3.3)
After 4 minutes	112 (4.4)
After 5 minutes	140 (5.5)

(h) *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27, appendix A, 40 CFR Part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H₂ O (18 in. H₂ O), gauge. The maximum allowable 5-minute pressure change (Δ p) which shall be met at any time is shown in the third column of Table 2 of §63.425(e)(1).

(i) *Railcar bubble leak test procedures.* As an alternative to paragraph (e) of this section for annual certification leakage testing of gasoline cargo tanks, the owner or operator may comply with paragraphs (i)(1) and (2) of this section for railcar gasoline cargo tanks, provided the railcar tank meets the requirement in paragraph (i)(3) of this section.

(1) Comply with the requirements of 49 CFR 173.31(d), 179.7, 180.509, and 180.511 for the testing of railcar gasoline cargo tanks.

(2) The leakage pressure test procedure required under 49 CFR 180.509(j) and used to show no indication of leakage under 49 CFR 180.511(f) shall be ASTM E 515-95 (incorporated by reference, see §63.14), BS EN 1593:1999 (incorporated by reference, see §63.14), or another bubble leak test procedure meeting the requirements in 49 CFR 179.7, 180.505, and 180.509.

(3) The alternative requirements in this paragraph (i) may not be used for any railcar gasoline cargo tank that collects gasoline vapors from a vapor balance system permitted under or required by a Federal, State, local, or tribal agency. A vapor balance system is a piping and collection system designed to collect gasoline vapors displaced from a storage vessel, barge, or other container being loaded, and routes the displaced gasoline vapors into the railcar gasoline cargo tank from which liquid gasoline is being unloaded.

[59 FR 64318, Dec. 14, 1994; 60 FR 7627, Feb. 8, 1995; 60 FR 32913, June 26, 1995; 68 FR 70965, Dec. 19, 2003]

[↑ Back to Top](#)

§63.426 Alternative means of emission limitation.

For determining the acceptability of alternative means of emission limitation for storage vessels under §63.423, the provisions of §60.114b of this chapter apply.

[↑ Back to Top](#)

§63.427 Continuous monitoring.

(a) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section, except as allowed in paragraph (a)(5) of this section.

(1) Where a carbon adsorption system is used, a continuous emission monitoring system (CEMS) capable of measuring organic compound concentration shall be installed in the exhaust air stream.

(2) Where a refrigeration condenser system is used, a continuous parameter monitoring system (CPMS) capable of measuring temperature shall be installed immediately downstream from the outlet to the condenser section. Alternatively, a CEMS capable of measuring organic compound concentration may be installed in the exhaust air stream.

(3) Where a thermal oxidation system other than a flare is used, a CPMS capable of measuring temperature must be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs.

(4) Where a flare meeting the requirements in §63.11(b) is used, a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple, must be installed in proximity to the pilot light to indicate the presence of a flame.

(5) Monitoring an alternative operating parameter or a parameter of a vapor processing system other than those listed in this paragraph will be allowed upon demonstrating to the

Administrator's satisfaction that the alternative parameter demonstrates continuous compliance with the emission standard in §63.422(b) or §60.112b(a)(3)(ii) of this chapter.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described in paragraphs (a)(1) and (a)(2) of this section, or to go below the operating parameter value for the parameter described in paragraph (a)(3) of this section, and established using the procedures in §63.425(b). In cases where an alternative parameter pursuant to paragraph (a)(5) of this section is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value. Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as specified above, shall constitute a violation of the emission standard in §63.422(b).

(c) Each owner or operator of gasoline storage vessels subject to the provisions of §63.423 shall comply with the monitoring requirements in §60.116b of this chapter, except records shall be kept for at least 5 years. If a closed vent system and control device are used, as specified in §60.112b(a)(3) of this chapter, to comply with the requirements in §63.423, the owner or operator shall also comply with the requirements in paragraph (a) of this section.

[59 FR 46350, Sept. 8, 1994, as amended at 68 FR 70966, Dec. 19, 2003]

[↑ Back to Top](#)

§63.428 Reporting and recordkeeping.

(a) The initial notifications required for existing affected sources under §63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by December 16, 1996, whichever is later. Affected sources that are major sources on December 16, 1996 and plan to be area sources by December 15, 1997 shall include in this notification a brief, non-binding description of and schedule for the action(s) that are planned to achieve area source status.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as follows:

(1) Annual certification testing performed under §63.425(e) and railcar bubble leak testing performed under §63.425(i); and

(2) Continuous performance testing performed at any time at that facility under §63.425 (f), (g), and (h).

(3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:

(i) Name of test: Annual Certification Test—Method 27 (§63.425(e)(1)); Annual Certification Test—Internal Vapor Valve (§63.425(e)(2)); Leak Detection Test (§63.425(f)); Nitrogen Pressure Decay Field Test (§63.425(g)); Continuous Performance Pressure Decay Test (§63.425(h)); or Railcar Bubble Leak Test Procedure (§63.425(i)).

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

(vi) Witnessing inspector, if any: Name, signature, and affiliation.

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the notification of compliance status required under §63.9(h):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.425(b); and

(ii) The following information when using a flare under provisions of §63.11(b) to comply with §63.422(b):

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and

(B) All visible emissions readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.425(a).

(3) If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.427(a), the owner or operator shall submit

a description of planned reporting and recordkeeping procedures. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application.

(d) Each owner or operator of storage vessels subject to the provisions of this subpart shall keep records and furnish reports as specified in §60.115b of this chapter, except records shall be kept for at least 5 years.

(e) Each owner or operator complying with the provisions of §63.424 (a) through (d) shall record the following information in the log book for each leak that is detected:

(1) The equipment type and identification number;

(2) The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell);

(3) The date the leak was detected and the date of each attempt to repair the leak;

(4) Repair methods applied in each attempt to repair the leak;

(5) “Repair delayed” and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak;

(6) The expected date of successful repair of the leak if the leak is not repaired within 15 days; and

(7) The date of successful repair of the leak.

(f) Each owner or operator subject to the provisions of §63.424 shall report to the Administrator a description of the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under §63.424(f), the report shall contain a full description of the program.

(1) In the case of an existing source or a new source that has an initial startup date before the effective date, the report shall be submitted with the notification of compliance status required under §63.9(h), unless an extension of compliance is granted under §63.6(i). If an extension of compliance is granted, the report shall be submitted on a date scheduled by the Administrator.

(2) In the case of new sources that did not have an initial startup date before the effective date, the report shall be submitted with the application for approval of construction, as described in §63.5(d).

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual report to the Administrator the following information, as applicable:

(1) Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility;

(2) Periodic reports required under paragraph (d) of this section; and

(3) The number of equipment leaks not repaired within 5 days after detection.

(h) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with §63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

(1) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(2) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

(3) Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.422(c)(2).

(4) For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:

(i) The date on which the leak was detected;

(ii) The date of each attempt to repair the leak;

(iii) The reasons for the delay of repair; and

(iv) The date of successful repair.

(i) Each owner or operator of a facility meeting the criteria in §63.420(c) shall perform the requirements of this paragraph (i), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 16, 1996 for existing facilities, within 30 days for existing facilities subject to §63.420(c) after December 16, 1996, or at startup for new facilities the methods, procedures, and assumptions supporting the calculations for determining criteria in §63.420(c);

(2) Maintain records to document that the facility parameters established under §63.420(c) have not been exceeded; and

(3) Report annually to the Administrator that the facility parameters established under §63.420(c) have not been exceeded.

(4) At any time following the notification required under paragraph (i)(1) of this section and approval by the Administrator of the facility parameters, and prior to any of the parameters being exceeded, the owner or operator may submit a report to request modification of any facility parameter to the Administrator for approval. Each such request shall document any expected HAP emission change resulting from the change in parameter.

(j) Each owner or operator of a facility meeting the criteria in §63.420(d) shall perform the requirements of this paragraph (j), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 16, 1996 for existing facilities, within 30 days for existing facilities subject to §63.420(d) after December 16, 1996, or at startup for new facilities the use of the emission screening equations in §63.420(a)(1) or (b)(1) and the calculated value of E_T or E_P ;

(2) Maintain a record of the calculations in §63.420 (a)(1) or (b)(1), including methods, procedures, and assumptions supporting the calculations for determining criteria in §63.420(d); and

(3) At any time following the notification required under paragraph (j)(1) of this section, and prior to any of the parameters being exceeded, the owner or operator may notify the Administrator of modifications to the facility parameters. Each such notification shall document any expected HAP emission change resulting from the change in parameter.

(k) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraph (b) of this section, an owner or operator may comply with the requirements in either paragraph (k)(1) or (2) of this section.

(1) An electronic copy of each record is instantly available at the terminal.

(i) The copy of each record in paragraph (k)(1) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(1) of this section.

(2) For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.

(i) The copy of each record in paragraph (k)(2) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(2) of this section.

[59 FR 64318, Dec. 14, 1994, as amended at 61 FR 7723, Feb. 29, 1996; 62 FR 9093, Feb. 28, 1997; 68 FR 70966, Dec. 19, 2003; 71 FR 17358, Apr. 6, 2006]

[↑ Back to Top](#)

§63.429 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.420, 63.422 through 63.423, and 63.424. Any owner or operator requesting to use an alternative means of emission limitation for storage vessels covered by §63.423 must follow the procedures in §63.426.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart, and any alternatives to §63.427(a)(1) through (4) per §63.427(a)(5).

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37348, June 23, 2003]

[↑ Back to Top](#)

**Table 1 to Subpart R of Part 63—General Provisions
Applicability to Subpart R**

Reference	Applies to subpart R	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	Yes	
63.1(a)(5)	No	Section reserved
63.1(a)(6)(8)	Yes	
63.1(a)(9)	No	Section reserved
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12))-(a)(14)	Yes	
63.1(b)(1)	No	Subpart R specifies applicability in §63.420
63.1(b)(2)	Yes	
63.1(b)(3)	No	Subpart R specifies reporting and recordkeeping for some large area sources in §63.428
63.1(c)(1)	Yes	
63.1(c)(2)	Yes	Some small sources are not subject to subpart R
63.1(c)(3)	No	Section reserved
63.1(c)(4)	Yes	
63.1(c)(5)	Yes	
63.1(d)	No	Section reserved
63.1(e)	Yes	
63.2	Yes	Additional definitions in §63.421
63.3(a)-(c)	Yes	
63.4(a)(1)-(a)(3)	Yes	
63.4(a)(4)	No	Section reserved
63.4(a)(5)	Yes	
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)(1)	Yes	
63.5(a)(2)	Yes	

63.5(b)(1)	Yes	
63.5(b)(2)	No	Section reserved
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	
63.5(b)(5)	Yes	
63.5(b)(6)	Yes	
63.5(c)	No	Section reserved
63.5(d)(1)	Yes	
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)(1)	Yes	
63.5(f)(2)	Yes	
63.6(a)	Yes	
63.6(b)(1)	Yes	
63.6(b)(2)	Yes	
63.6(b)(3)	Yes	
63.6(b)(4)	Yes	
63.6(b)(5)	Yes	
63.6(b)(6)	No	Section reserved
63.6(b)(7)	Yes	
63.6(c)(1)	No	Subpart R specifies the compliance date
63.6(c)(2)	Yes	
63.6(c)(3)-(c)(4)	No	Sections reserved
63.6(c)(5)	Yes	
63.6(d)	No	Section reserved
63.6(e)	Yes	
63.6(f)(1)	Yes	
63.6(f)(2)	Yes	
63.6(f)(3)	Yes	
63.6(g)	Yes	
63.6(h)	No	Subpart R does not require COMS
63.6(i)(1)-(i)(14)	Yes	
63.6(i)(15)	No	Section reserved

63.6(i)(16)	Yes	
63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)	Yes	
63.7(a)(3)	Yes	
63.7(b)	Yes	
63.7(c)	Yes	
63.7(d)	Yes	
63.7(e)(1)	Yes	
63.7(e)(2)	Yes	
63.7(e)(3)	Yes	
63.7(e)(4)	Yes	
63.7(f)	Yes	
63.7(g)	Yes	
63.7(h)	Yes	
63.8(a)(1)	Yes	
63.8(a)(2)	Yes	
63.8(a)(3)	No	Section reserved
63.8(a)(4)	Yes	
63.8(b)(1)	Yes	
63.8(b)(2)	Yes	
63.8(b)(3)	Yes	
63.8(c)(1)	Yes	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	
63.8(c)(4)	Yes	
63.8(c)(5)	No	Subpart R does not require COMS
63.8(c)(6)-(c)(8)	Yes	
63.8(d)	Yes	
63.8(e)	Yes	
63.8(f)(1)-(f)(5)	Yes	
63.8(f)(6)	Yes	
63.8(g)	Yes	
63.9(a)	Yes	
63.9(b)(1)	Yes	

63.9(b)(2)	No	Subpart R allows additional time for existing sources to submit initial notification. Sec. 63.428(a) specifies submittal by 1 year after being subject to the rule or December 16, 1996, whichever is later.
63.9(b)(3)	Yes	
63.9(b)(4)	Yes	
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	Yes	
63.9(f)	Yes	
63.9(g)	Yes	
63.9(h)(1)-(h)(3)	Yes	
63.9(h)(4)	No	Section reserved
63.9(h)(5)-(h)(6)	Yes	
63.9(i)	Yes	
63.9(j)	Yes	
63.10(a)	Yes	
63.10(b)(1)	Yes	
63.10(b)(2)	Yes	
63.10(b)(3)	Yes	
63.10(c)(1)	Yes	
63.10(c)(2)-(c)(4)	No	Sections reserved
63.10(c)(5)-(c)(8)	Yes	
63.10(c)(9)	No	Section reserved
63.10(c)(5)-(c)(8)	Yes	
63.10(d)(1)	Yes	
63.10(d)(2)	Yes	
63.10(d)(3)	Yes	
63.10(d)(4)	Yes	
63.10(d)(5)	Yes	
63.10(e)	Yes	
63.10(f)	Yes	
63.11(a)-(b)	Yes	

63.11(c), (d), and (e)	Yes	
63.12(a)-(c)	Yes	
63.13(a)-(c)	Yes	
63.14(a)-(b)	Yes	
63.15(a)-(b)	Yes	

[59 FR 64318, Dec. 14, 1994, as amended at 61 FR 7724, Feb. 29, 1996; 73 FR 78213, Dec. 22, 2008]

Appendix N

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

Contents

<u>§63.640</u>	<u>Applicability and designation of affected source.</u>
<u>§63.641</u>	<u>Definitions.</u>
<u>§63.642</u>	<u>General standards.</u>
<u>§63.643</u>	<u>Miscellaneous process vent provisions.</u>
<u>§63.644</u>	<u>Monitoring provisions for miscellaneous process vents.</u>
<u>§63.645</u>	<u>Test methods and procedures for miscellaneous process vents.</u>
<u>§63.646</u>	<u>Storage vessel provisions.</u>
<u>§63.647</u>	<u>Wastewater provisions.</u>
<u>§63.648</u>	<u>Equipment leak standards.</u>
<u>§63.649</u>	<u>Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.</u>
<u>§63.650</u>	<u>Gasoline loading rack provisions.</u>
<u>§63.651</u>	<u>Marine tank vessel loading operation provisions.</u>
<u>§63.652</u>	<u>Emissions averaging provisions.</u>
<u>§63.653</u>	<u>Monitoring, recordkeeping, and implementation plan for emissions averaging.</u>
<u>§63.654</u>	<u>Heat exchange systems.</u>
<u>§63.655</u>	<u>Reporting and recordkeeping requirements.</u>
<u>§63.656</u>	<u>Implementation and enforcement.</u>
<u>§63.657</u>	<u>Delayed coking unit decoking operation standards.</u>
<u>§63.658</u>	<u>Fenceline monitoring provisions.</u>
<u>§63.660</u>	<u>Storage vessel provisions.</u>
<u>§63.670</u>	<u>Requirements for flare control devices.</u>
<u>§63.671</u>	<u>Requirements for flare monitoring systems.</u>
<u>§§63.672-63.679</u>	<u>[Reserved]</u>
<u>Appendix to Subpart CC of Part 63—Tables</u>	

SOURCE: 60 FR 43260, Aug. 18, 1995, unless otherwise noted.

§63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section:

(1) Are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and

(2) Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.

(b)(1) If the predominant use of the flexible operation unit, as described in paragraphs (b)(1)(i) and (ii) of this section, is as a petroleum refining process unit, as defined in §63.641, then the flexible operation unit shall be subject to the provisions of this subpart.

(i) Except as provided in paragraph (b)(1)(ii) of this section, the predominant use of the flexible operation unit shall be the use representing the greatest annual operating time.

(ii) If the flexible operation unit is used as a petroleum refining process unit and for another purpose equally based on operating time, then the predominant use of the flexible operation unit shall be the use that produces the greatest annual production on a mass basis.

(2) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units shall be reported as specified in §63.655(h)(6)(i).

(c) For the purposes of this subpart, the affected source shall comprise all emissions points, in combination, listed in paragraphs (c)(1) through (9) of this section that are located at a single refinery plant site.

(1) All miscellaneous process vents from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(2) All storage vessels associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(3) All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(4) All equipment leaks from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(5) All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in paragraph (a) of this section;

(6) All marine vessel loading operations located at a petroleum refinery meeting the criteria in paragraph (a) of this section and the applicability criteria of subpart Y, §63.560;

(7) All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a

contiguous area and under common control with a refinery meeting the criteria in paragraph (a) of this section; and

(8) All heat exchange systems, as defined in this subpart.

(9) All releases associated with the decoking operations of a delayed coking unit, as defined in this subpart.

(d) The affected source subject to this subpart does not include the emission points listed in paragraphs (d)(1) through (d)(5) of this section.

(1) Stormwater from segregated stormwater sewers;

(2) Spills;

(3) Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in §63.641 of this subpart, for less than 300 hours during the calendar year;

(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents; and

(5) Emission points routed to a fuel gas system, as defined in §63.641, provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are subject to §63.670. No other testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

(e) The owner or operator of a storage vessel constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (e)(1) and (e)(2) of this section to determine whether a storage vessel is part of a source to which this subpart applies. The owner or operator of a storage vessel constructed after August 18, 1994, shall follow the procedures specified in paragraphs (e)(1), (e)(2)(i), and (e)(2)(ii) of this section to determine whether a storage vessel is part of a source to which this subpart applies.

(1) Where a storage vessel is used exclusively by a process unit, the storage vessel shall be considered part of that process unit.

(i) If the process unit is a petroleum refining process unit subject to this subpart, then the storage vessel is part of the affected source to which this subpart applies.

(ii) If the process unit is not subject to this subpart, then the storage vessel is not part of the affected source to which this subpart applies.

(2) If a storage vessel is not dedicated to a single process unit, then the applicability of this subpart shall be determined according to the provisions in paragraphs (e)(2)(i) through (e)(2)(iii) of this section.

(i) If a storage vessel is shared among process units and one of the process units has the predominant use, as determined by paragraphs (e)(2)(i)(A) and (e)(2)(i)(B) of this section, then the storage vessel is part of that process unit.

(A) If the greatest input on a volume basis into the storage vessel is from a process unit that is located on the same plant site, then that process unit has the predominant use.

(B) If the greatest input on a volume basis into the storage vessel is provided from a process unit that is not located on the same plant site, then the predominant use shall be the process unit that receives the greatest amount of material on a volume basis from the storage vessel at the same plant site.

(ii) If a storage vessel is shared among process units so that there is no single predominant use, and at least one of those process units is a petroleum refining process unit subject to this subpart, the storage vessel shall be considered to be part of the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the storage vessel to any of the petroleum refining process units subject to this subpart.

(iii) If the predominant use of a storage vessel varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that storage vessel during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(ii).

(f) The owner or operator of a distillation unit constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(4) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies. The owner or operator of a distillation unit constructed after August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(5) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies.

(1) If the greatest input to the distillation unit is from a process unit located on the same plant site, then the distillation unit shall be assigned to that process unit.

(2) If the greatest input to the distillation unit is provided from a process unit that is not located on the same plant site, then the distillation unit shall be assigned to the process unit located at the same plant site that receives the greatest amount of material from the distillation unit.

(3) If a distillation unit is shared among process units so that there is no single predominant use, as described in paragraphs (f)(1) and (f)(2) of this section, and at least one of those process units is a petroleum refining process unit subject to this subpart, the distillation unit shall be assigned

to the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the distillation unit to any of the petroleum refining process units subject to this rule.

(4) If the process unit to which the distillation unit is assigned is a petroleum refining process unit subject to this subpart and the vent stream contains greater than 20 parts per million by volume total organic hazardous air pollutants, then the vent from the distillation unit is considered a miscellaneous process vent (as defined in §63.641 of this subpart) and is part of the source to which this subpart applies.

(5) If the predominant use of a distillation unit varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that distillation unit during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(iii).

(g) The provisions of this subpart do not apply to the processes specified in paragraphs (g)(1) through (g)(7) of this section.

(1) Research and development facilities, regardless of whether the facilities are located at the same plant site as a petroleum refining process unit that is subject to the provisions of this subpart;

(2) Equipment that does not contain any of the hazardous air pollutants listed in table 1 of this subpart that is located within a petroleum refining process unit that is subject to this subpart;

(3) Units processing natural gas liquids;

(4) Units that are used specifically for recycling discarded oil;

(5) Shale oil extraction units;

(6) Ethylene processes; and

(7) Process units and emission points subject to subparts F, G, H, and I of this part.

(h) Sources subject to this subpart are required to achieve compliance on or before the dates specified in table 11 of this subpart, except as provided in paragraphs (h)(1) through (3) of this section.

(1) Marine tank vessels at existing sources shall be in compliance with this subpart, except for §§63.657 through 63.660, no later than August 18, 1999, unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998, unless an extension has been granted by the Administrator as provided in §63.6(i).

(2) Existing Group 1 floating roof storage vessels meeting the applicability criteria in item 1 of the definition of Group 1 storage vessel shall be in compliance with §63.646 at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, whichever is first.

(3) An owner or operator may elect to comply with the provisions of §63.648(c) through (i) as an alternative to the provisions of §63.648(a) and (b). In such cases, the owner or operator shall comply no later than the dates specified in paragraphs (h)(3)(i) through (iii) of this section.

(i) Phase I (see table 2 of this subpart), beginning on August 18, 1998;

(ii) Phase II (see table 2 of this subpart), beginning no later than August 18, 1999; and

(iii) Phase III (see table 2 of this subpart), beginning no later than February 18, 2001.

(i) If an additional petroleum refining process unit is added to a plant site that is a major source as defined in section 112(a) of the Clean Air Act, the addition shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (i)(1) through (i)(3) of this section:

(1) It is an addition that meets the definition of construction in §63.2 of subpart A of this part;

(2) Such construction commenced after July 14, 1994; and

(3) The addition has the potential to emit 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

(j) If any change is made to a petroleum refining process unit subject to this subpart, the change shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (j)(1) and (j)(2) of this section:

(1) It is a change that meets the definition of reconstruction in §63.2 of subpart A of this part; and

(2) Such reconstruction commenced after July 14, 1994.

(k) If an additional petroleum refining process unit is added to a plant site or a change is made to a petroleum refining process unit and the addition or change is determined to be subject to the new source requirements according to paragraphs (i) or (j) of this section it must comply with the requirements specified in paragraphs (k)(1) and (k)(2) of this section:

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements in item (1), (2), or (3) of table 11 of this subpart, as applicable, upon initial startup of the reconstructed source or by August 18, 1995, whichever is later; and

(2) The owner or operator of the reconstructed source, addition, or change shall comply with the reporting and recordkeeping requirements that are applicable to new sources. The applicable reports include, but are not limited to:

(i) The application for approval of construction or reconstruction shall be submitted as soon as practical before the construction or reconstruction is planned to commence (but it need not be sooner than November 16, 1995);

(ii) The Notification of Compliance Status report as required by §63.655(f) for a new source, addition, or change;

(iii) Periodic Reports and other reports as required by §63.655(g) and (h);

(iv) Reports and notifications required by §60.487 of subpart VV of part 60 or §63.182 of subpart H of this part. The requirements for subpart H are summarized in table 3 of this subpart;

(v) Reports required by 40 CFR 61.357 of subpart FF;

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation that meets the criteria in paragraphs (c)(1) through (9) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emissions point(s) (as defined in §63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraph (i) or (j) of this section, the requirements in paragraphs (l)(1) through (4) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph (l) and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by §63.655(f).

(1) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit are subject to the requirements for an existing source.

(2) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit shall be in compliance with the applicable requirements in item (4) of table 11 of this subpart by the dates specified in paragraph (l)(2)(i) or (ii) of this section.

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by the applicable compliance date in item (4) of table 11 of this subpart, whichever is later.

(ii) If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), the owner or operator shall be in compliance upon initial startup or by August 18, 1998, whichever is later, unless the owner or operator demonstrates to the Administrator that achieving compliance will take longer than making the change. If this demonstration is made to the Administrator's satisfaction, the owner or operator shall follow the procedures in paragraphs (m)(1) through (m)(3) of this section to establish a compliance date.

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation meeting the criteria in paragraphs (c)(1) through (9) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. A process change to an existing petroleum refining process unit shall be subject to the reporting requirements for existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. The applicable reports include, but are not limited to:

(i) The Notification of Compliance Status report as required by §63.655(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.655(g) and (h);

(iii) Reports and notifications required by sections of subpart A of this part that are applicable to this subpart, as identified in table 6 of this subpart.

(iv) Reports and notifications required by §63.182, or 40 CFR 60.487. The requirements of subpart H of this part are summarized in table 3 of this subpart;

(v) Reports required by §61.357 of subpart FF;

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y. These requirements are summarized in table 5 of this subpart.

(4) If pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems are added to an existing source, they are

subject to the equipment leak standards for existing sources in §63.648. A notification of compliance status report shall not be required for such added equipment.

(m) If a change that does not meet the criteria in paragraph (l) of this section is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), then the owner or operator shall comply with the applicable requirements of this subpart for existing sources, as specified in item (4) of table 11 of this subpart, for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

(1) The owner or operator shall submit to the Administrator for approval a compliance schedule, along with a justification for the schedule.

(2) The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within 180 days of the date when the affect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

(3) The Administrator shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the Administrator within 120 calendar days of receipt.

(n) Overlap of this subpart with other regulations for storage vessels. As applicable, paragraphs (n)(1), (3), (4), (6), and (7) of this section apply for Group 2 storage vessels and paragraphs (n)(2) and (5) of this section apply for Group 1 storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section. After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 61, subpart Y, is required to comply only with the requirements of 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section.

(2) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb, is required to comply only with either 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section or this subpart. After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 61, subpart Y, is required to comply only with either 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section or this subpart.

(3) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 60.110b, but is not required to apply controls by 40 CFR 60.110b or 60.112b, is required to comply only with this subpart.

(4) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 61.270, but is not required to apply controls by 40 CFR 61.271, is required to comply only with this subpart.

(5) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subpart K or Ka, is required to only comply with the provisions of this subpart.

(6) After compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the control requirements of 40 CFR part 60, subparts K or Ka is required to comply only with the provisions of 40 CFR part 60, subparts K or Ka except as provided for in paragraph (n)(9) of this section.

(7) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to 40 CFR part 60, subparts K or Ka, but not to the control requirements of 40 CFR part 60, subparts K or Ka, is required to comply only with this subpart.

(8) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 60, subpart Kb, except as provided in paragraphs (n)(8)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in paragraphs (n)(8)(i) through (viii) of this section.

(i) Storage vessels that are to comply with §60.112b(a)(2) of subpart Kb are exempt from the secondary seal requirements of §60.112b(a)(2)(i)(B) during the gap measurements for the primary seal required by §60.113b(b) of subpart Kb.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113b(b) of this chapter or to inspect the vessel to determine compliance with §60.113b(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(iii) If a failure is detected during the inspections required by §60.113b(a)(2) or during the seal gap measurements required by §60.113b(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(8)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §60.113b(a)(2) or §60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with subpart Kb of part 60 may submit the inspection reports required by §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb as part of the periodic reports required by this subpart, rather than within the 30-day period specified in §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb.

(vi) The reports of rim seal inspections specified in §60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §60.113b(b)(4). Documentation of the inspections shall be recorded as specified in §60.115b(b)(3).

(vii) To be in compliance with §60.112b(a)(1)(iv) or (a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.*, pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the “no visible gap” requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 60, subpart Kb of this chapter for that flare.

(9) Storage vessels described by paragraph (n)(6) of this section that are to comply with 40 CFR part 60, subpart Ka, are to comply with only subpart Ka except as provided for in paragraphs (n)(9)(i) through (n)(9)(iv) of this section.

(i) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113a(a)(1) of this chapter because the floating roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(ii) If a failure is detected during the seal gap measurements required by §60.113a(a)(1) of subpart Ka, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to 2 extensions of up to 30 additional calendar days each.

(iii) If an extension is utilized in accordance with paragraph (n)(9)(ii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, describe the nature and date of the repair made or provide the date the storage vessel was emptied. The owner or operator shall also provide documentation of the decision to utilize an extension including a description of the failure, documentation that alternate storage capacity is unavailable, and a schedule of actions that will ensure that the control equipment will be repaired or the vessel emptied as soon as possible.

(iv) Owners and operators of storage vessels complying with subpart Ka of part 60 may submit the inspection reports required by §60.113a(a)(1)(i)(E) of subpart Ka as part of the periodic reports required by this subpart, rather than within the 60-day period specified in §60.113a(a)(1)(i)(E) of subpart Ka.

(10) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 61, subpart Y, except as provided in paragraphs (n)(10)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 61, subpart Y, shall comply with subpart Y except as provided for in paragraphs (n)(10)(i) through (viii) of this section.

(i) Storage vessels that are to comply with §61.271(b) of this chapter are exempt from the secondary seal requirements of §61.271(b)(2)(ii) of this chapter during the gap measurements for the primary seal required by §61.272(b) of this chapter.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §61.272(b) of this chapter or to inspect the vessel to determine compliance with §61.272(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(iii) If a failure is detected during the inspections required by §61.272(a)(2) of this chapter or during the seal gap measurements required by §61.272(b)(1) of this chapter, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(10)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §61.272(a)(2) or (b)(4)(iii) of this chapter, and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with 40 CFR part 61, subpart Y, may submit the inspection reports required by §61.275(a), (b)(1), and (d) of this chapter as part of the periodic reports required by this subpart, rather than within the 60-day period specified in §61.275(a), (b)(1), and (d) of this chapter.

(vi) The reports of rim seal inspections specified in §61.275(d) of this chapter are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §61.272(b)(4) of this chapter. Documentation of the inspections shall be recorded as specified in §61.276(a) of this chapter.

(vii) To be in compliance with §61.271(a)(6) or (b)(3) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.*, pole float system, pole sleeve

system, internal sleeve system or flexible enclosure system) as appropriate to comply with the “no visible gap” requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 61, subpart Y of this chapter for that flare.

(o) Overlap of this subpart CC with other regulations for wastewater.

(1) After the compliance dates specified in paragraph (h) of this section a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 or Group 2 wastewater stream that is conveyed, stored, or treated in a wastewater stream management unit that also receives streams subject to the provisions of §§63.133 through 63.147 of subpart G wastewater provisions of this part shall comply as specified in paragraph (o)(2)(i) or (o)(2)(ii) of this section. Compliance with the provisions of paragraph (o)(2) of this section shall constitute compliance with the requirements of this subpart for that wastewater stream.

(i) Comply with paragraphs (o)(2)(i)(A) through (D) of this section.

(A) The provisions in §§63.133 through 63.140 of subpart G for all equipment used in the storage and conveyance of the Group 1 or Group 2 wastewater stream.

(B) The provisions in both 40 CFR part 61, subpart FF and in §§63.138 and 63.139 of subpart G for the treatment and control of the Group 1 or Group 2 wastewater stream.

(C) The provisions in §§63.143 through 63.148 of subpart G for monitoring and inspections of equipment and for recordkeeping and reporting requirements. The owner or operator is not required to comply with the monitoring, recordkeeping, and reporting requirements associated with the treatment and control requirements in 40 CFR part 61, subpart FF, §§61.355 through 61.357.

(D) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of §63.670.

(ii) Comply with paragraphs (o)(2)(ii)(A) through (C) of this section.

(A) Comply with the provisions of §§63.133 through 63.148 and §§63.151 and 63.152 of subpart G.

(B) For any Group 2 wastewater stream or organic stream whose benzene emissions are subject to control through the use of one or more treatment processes or waste management units under

the provisions of 40 CFR part 61, subpart FF on or after December 31, 1992, comply with the requirements of §63.133 through §63.147 of subpart G for Group 1 wastewater streams.

(C) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of §63.670.

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (h) of this section, equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart.

(2) Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

(q) For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

(r) Overlap of subpart CC with other regulations for gasoline loading racks. After the compliance dates specified in paragraph (h) of this section, a Group 1 gasoline loading rack that is part of a source subject to subpart CC and also is subject to the provisions of 40 CFR part 60, subpart XX is required to comply only with this subpart.

(s) Overlap of this subpart with other regulation for flares. On January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and subject to this subpart are required to comply only with the provisions specified in this subpart. Prior to January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and elect to comply with the requirements in §§63.670 and 63.671 are required to comply only with the provisions specified in this subpart.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29878, June 12, 1996; 63 FR 44140, Aug. 18, 1998; 66 FR 28841, May 25, 2001; 74 FR 55683, Oct. 28, 2009; 78 FR 37145, June 20, 2013; 80 FR 75237, Dec. 1, 2015]

§63.641 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act, subpart A of this part, and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Affected source means the collection of emission points to which this subpart applies as determined by the criteria in §63.640.

Aliphatic means open-chained structure consisting of paraffin, olefin and acetylene hydrocarbons and derivatives.

Annual average true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the annual average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local annual average temperature reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

- (1) In accordance with methods specified in §63.111 of subpart G of this part;
- (2) From standard reference texts; or
- (3) By any other method approved by the Administrator.

Assist air means all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air.

Assist steam means all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist steam* includes, but is not necessarily limited to, center steam, lower steam and upper steam.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not by carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Center steam means the portion of assist steam introduced into the stack of a flare to reduce burnback.

Closed blowdown system means a system used for depressuring process vessels that is not open to the atmosphere and is configured of piping, ductwork, connections, accumulators/knockout drums, and, if necessary, flow inducing devices that transport gas or vapor from a process vessel to a control device or back into the process.

Closed vent system means a system that is not open to the atmosphere and is configured of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors.

Combustion zone means the area of the flare flame where the combustion zone gas combines for combustion.

Combustion zone gas means all gases and vapors found just after a flare tip. This gas includes all flare vent gas, total steam, and premix air.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are accessible.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every hour and recorded at the frequency specified in §63.655(i).

Continuous recorder means a data recording device recording an instantaneous data value or an average data value at least once every hour.

Control device means any equipment used for recovering, removing, or oxidizing organic hazardous air pollutants. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For miscellaneous process vents (as defined in this section), recovery devices (as defined in this section) are not considered control devices.

Cooling tower means a heat removal device used to remove the heat absorbed in circulating cooling water systems by transferring the heat to the atmosphere using natural or mechanical draft.

Cooling tower return line means the main water trunk lines at the inlet to the cooling tower before exposure to the atmosphere.

Decoking operations means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. *Decoking operations* begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged via the unit's blowdown system but instead is vented

directly to the atmosphere. *Decoking operations* include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Delayed coker vent means a miscellaneous process vent that contains uncondensed vapors from the delayed coking unit's blowdown system. Venting from the *delayed coker vent* is typically intermittent in nature, and occurs primarily during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery. The emissions from the decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be *delayed coker vents*.

Distillate receiver means overhead receivers, overhead accumulators, reflux drums, and condenser(s) including ejector-condenser(s) associated with a distillation unit.

Distillation unit means a device or vessel in which one or more feed streams are separated into two or more exit streams, each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and the vapor phases by vaporization and condensation as they approach equilibrium within the distillation unit. Distillation unit includes the distillate receiver, reboiler, and any associated vacuum pump or steam jet.

Emission point means an individual miscellaneous process vent, storage vessel, wastewater stream, equipment leak, decoking operation or heat exchange system associated with a petroleum refining process unit; an individual storage vessel or equipment leak associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911; a gasoline loading rack classified under Standard Industrial Classification code 2911; or a marine tank vessel loading operation located at a petroleum refinery.

Equipment leak means emissions of organic hazardous air pollutants from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system “in organic hazardous air pollutant service” as defined in this section. Vents from wastewater collection and conveyance systems (including, but not limited to wastewater drains, sewer vents, and sump drains), tank mixers, and sample valves on storage tanks are not equipment leaks.

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flare means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this rule, the definition of *flare* includes, but is not necessarily limited to, air-assisted flares, steam-assisted flares and non-assisted flares.

Flare purge gas means gas introduced between a flare header's water seal and the flare tip to prevent oxygen infiltration (backflow) into the flare tip. For a flare with no water seal, the function of *flare purge gas* is performed by flare sweep gas and, therefore, by definition, such a flare has no *flare purge gas*.

Flare supplemental gas means all gas introduced to the flare in order to improve the combustible characteristics of combustion zone gas.

Flare sweep gas means, for a flare with a flare gas recovery system, the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup in the flare header; *flare sweep gas* in these flares is introduced prior to and recovered by the flare gas recovery system. For a flare without a flare gas recovery system, *flare sweep gas* means the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header and out the flare tip in order to prevent oxygen buildup in the flare header and to prevent oxygen infiltration (backflow) into the flare tip.

Flare vent gas means all gas found just prior to the flare tip. This gas includes all flare waste gas (*i.e.*, gas from facility operations that is directed to a flare for the purpose of disposing of the gas), that portion of flare sweep gas that is not recovered, flare purge gas and flare supplemental gas, but does not include pilot gas, total steam or assist air.

Flexible enclosure device means a seal made of an elastomeric fabric (or other material) which completely encloses a slotted guidepole or ladder and eliminates the vapor emission pathway from inside the storage vessel through the guidepole slots or ladder slots to the outside air.

Flexible operation unit means a process unit that manufactures different products periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in a line.

Force majeure event means a release of HAP, either directly to the atmosphere from a pressure relief device or discharged via a flare, that is demonstrated to the satisfaction of the Administrator to result from an event beyond the refinery owner or operator's control, such as natural disasters; acts of war or terrorism; loss of a utility external to the refinery (*e.g.*, external power curtailment), excluding power curtailment due to an interruptible service agreement; and fire or explosion originating at a near or adjoining facility outside of the refinery that impacts the refinery's ability to operate.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines.

Gasoline loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Group 1 gasoline loading rack means any gasoline loading rack classified under Standard Industrial Classification code 2911 that is located within a bulk gasoline terminal that has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput for the terminal as may be limited by compliance with enforceable conditions under Federal, State, or local law and discovered by the Administrator and any other person.

Group 1 marine tank vessel means a vessel at an existing source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals in bulk onto marine tank vessels, that emits greater than 9.1 megagrams of any individual HAP or 22.7 megagrams of any combination of HAP annually after August 18, 1999, or a vessel at a new source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals onto marine tank vessels.

Group 1 miscellaneous process vent means a miscellaneous process vent for which the total organic HAP concentration is greater than or equal to 20 parts per million by volume, and the total volatile organic compound emissions are greater than or equal to 33 kilograms per day for existing sources and 6.8 kilograms per day for new sources at the outlet of the final recovery device (if any) and prior to any control device and prior to discharge to the atmosphere.

Group 1 storage vessel means:

(1) Prior to February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

(2) On and after February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 5.2 kilopascals (0.75 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at an existing source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals (0.5 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iv) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

Group 1 wastewater stream means a wastewater stream at a petroleum refinery with a total annual benzene loading of 10 megagrams per year or greater as calculated according to the procedures in 40 CFR 61.342 of subpart FF of part 61 that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR part 61, subpart FF.

Group 2 gasoline loading rack means a gasoline loading rack classified under Standard Industrial Classification code 2911 that does not meet the definition of a Group 1 gasoline loading rack.

Group 2 marine tank vessel means a marine tank vessel that does not meet the definition of a Group 1 marine tank vessel.

Group 2 miscellaneous process vent means a miscellaneous process vent that does not meet the definition of a Group 1 miscellaneous process vent.

Group 2 storage vessel means a storage vessel that does not meet the definition of a Group 1 storage vessel.

Group 2 wastewater stream means a wastewater stream that does not meet the definition of Group 1 wastewater stream.

Hazardous air pollutant or *HAP* means one of the chemicals listed in section 112(b) of the Clean Air Act.

Heat exchange system means a device or collection of devices used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (*i.e.*, non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (e.g., river or pond water). For closed-loop recirculation systems, the *heat exchange system* consists of a cooling tower, all petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in this subpart, serviced by that cooling tower, and all water lines to and from these petroleum refinery process unit heat exchangers. For once-through systems, the *heat exchange system* consists of all heat exchangers that are in organic HAP service, as defined in this subpart, servicing an individual petroleum refinery process unit and all water lines to and from these heat exchangers. Sample coolers or pump seal coolers are not considered heat exchangers for the purpose of this definition and are not part of the *heat exchange system*. Intentional direct contact with process fluids results in the formation of a wastewater.

Heat exchanger exit line means the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere, in, as an example, a once-through cooling system, whichever occurs first.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.593(d) of part 60, subpart GGG.

In organic hazardous air pollutant service or *in organic HAP service* means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of

total organic HAP as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart. The provisions of §63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

Leakless valve means a valve that has no external actuating mechanism.

Lower steam means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the highest calendar-month average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

- (1) In accordance with methods specified in §63.111 of subpart G of this part;
- (2) From standard reference texts; or
- (3) By any other method approved by the Administrator.

Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged from a petroleum refining process unit meeting the criteria specified in §63.640(a). *Miscellaneous process vents* include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. *Miscellaneous process vents* include vent streams from: Caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum pumps, steam ejectors, hot wells, high point bleeds, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. *Miscellaneous process vents* do not include:

- (1) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are in compliance with §63.670;
- (2) Pressure relief device discharges;
- (3) Leaks from equipment regulated under §63.648;
- (4) [Reserved]
- (5) In situ sampling systems (onstream analyzers) until February 1, 2016. After this date, these sampling systems will be included in the definition of miscellaneous process vents and sampling

systems determined to be Group 1 miscellaneous process vents must comply with the requirements in §§63.643 and 63.644 no later than January 30, 2019;

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) Emissions associated with delayed coking unit decoking operations;

(12) Vents from storage vessels;

(13) Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and

(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

Net heating value means the energy released as heat when a compound undergoes complete combustion with oxygen to form gaseous carbon dioxide and gaseous water (also referred to as lower heating value).

Operating permit means a permit required by 40 CFR parts 70 or 71.

Organic hazardous air pollutant or *organic HAP* in this subpart, means any of the organic chemicals listed in table 1 of this subpart.

Perimeter assist air means the portion of assist air introduced at the perimeter of the flare tip or above the flare tip. *Perimeter assist air* includes air intentionally entrained in lower and upper steam. *Perimeter assist air* includes all assist air except premix assist air.

Periodically discharged means discharges that are intermittent and associated with routine operations, maintenance activities, startups, shutdowns, malfunctions, or process upsets.

Petroleum-based solvents means mixtures of aliphatic hydrocarbons or mixtures of one and two ring aromatic hydrocarbons.

Petroleum refining process unit means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911), and used primarily for the following:

- (1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
- (2) Separating petroleum; or
- (3) Separating, cracking, reacting, or reforming intermediate petroleum streams.
- (4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

Pilot gas means gas introduced into a flare tip that provides a flame to ignite the flare vent gas.

Plant site means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Premix assist air means the portion of assist air that is introduced to the flare vent gas, whether injected or induced, prior to the flare tip. Premix assist air also includes any air intentionally entrained in center steam.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means the equipment assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. A process unit includes any associated storage vessels. For the purpose of this subpart, process unit includes, but is not limited to, chemical manufacturing process units and petroleum refining process units.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not considered a process unit shutdown. An unscheduled work practice or operational

procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, or would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown is not considered a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not considered process unit shutdowns.

Recovery device means an individual unit of equipment capable of and used for the purpose of recovering chemicals for use, reuse, or sale. Recovery devices include, but are not limited to, absorbers, carbon adsorbers, and condensers.

Reference control technology for gasoline loading racks means a vapor collection and processing system used to reduce emissions due to the loading of gasoline cargo tanks to 10 milligrams of total organic compounds per liter of gasoline loaded or less.

Reference control technology for marine vessels means a vapor collection system and a control device that reduces captured HAP emissions by 97 percent.

Reference control technology for miscellaneous process vents means a combustion device used to reduce organic HAP emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume.

Reference control technology for storage vessels means either:

(1) For Group 1 storage vessels complying with §63.660:

(i) An internal floating roof, including an external floating roof converted to an internal floating roof, meeting the specifications of §63.1063(a)(1)(i) and (b);

(ii) An external floating roof meeting the specifications of §63.1063(a)(1)(ii), (a)(2), and (b); or

(iii) [Reserved]

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume (ppmv).

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

(2) For all other storage vessels:

(i) An internal floating roof meeting the specifications of §63.119(b) of subpart G except for §63.119(b)(5) and (6);

(ii) An external floating roof meeting the specifications of §63.119(c) of subpart G except for §63.119(c)(2);

(iii) An external floating roof converted to an internal floating roof meeting the specifications of §63.119(d) of subpart G except for §63.119(d)(2); or

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume.

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

Reference control technology for wastewater means the use of:

(1) Controls specified in §§61.343 through 61.347 of subpart FF of part 61;

(2) A treatment process that achieves the emission reductions specified in table 7 of this subpart for each individual HAP present in the wastewater stream or is a steam stripper that meets the specifications in §63.138(g) of subpart G of this part; and

(3) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices) the organic HAP emissions in the vapor streams vented from treatment processes (including the steam stripper described in paragraph (2) of this definition) managing wastewater.

Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

Regulated material means any stream associated with emission sources listed in §63.640(c) required to meet control requirements under this subpart as well as any stream for which this subpart or a cross-referencing subpart specifies that the requirements for flare control devices in §63.670 must be met.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

Shutdown means the cessation of a petroleum refining process unit or a unit operation (including, but not limited to, a distillation unit or reactor) within a petroleum refining process unit for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair.

Startup means the setting into operation of a petroleum refining process unit for purposes of production. Startup does not include operation solely for purposes of testing equipment. Startup does not include changes in product for flexible operation units.

Storage vessel means a tank or other vessel that is used to store organic liquids. Storage vessel does not include:

- (1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;
- (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (3) Vessels with capacities smaller than 40 cubic meters;
- (4) Bottoms receiver tanks; or
- (5) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

Temperature monitoring device means a unit of equipment used to monitor temperature and having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 0.5 °C, whichever is greater.

Thermal expansion relief valve means a pressure relief valve designed to protect equipment from excess pressure due to thermal expansion of blocked liquid-filled equipment or piping due to ambient heating or heat from a heat tracing system. Pressure relief valves designed to protect equipment from excess pressure due to blockage against a pump or compressor or due to fire contingency are not thermal expansion relief valves.

Total annual benzene means the total amount of benzene in waste streams at a facility on an annual basis as determined in §61.342 of 40 CFR part 61, subpart FF.

Total organic compounds or *TOC*, as used in this subpart, means those compounds excluding methane and ethane measured according to the procedures of Method 18 of 40 CFR part 60, appendix A. Method 25A may be used alone or in combination with Method 18 to measure TOC as provided in §63.645 of this subpart.

Total steam means the total of all steam that is supplied to a flare and includes, but is not limited to, lower steam, center steam and upper steam.

Upper steam means the portion of assist steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

Wastewater means water or wastewater that, during production or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product and is discharged into any individual drain system.

Examples are feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29879, June 12, 1996; 62 FR 7938, Feb. 21, 1997; 63 FR 31361, June 9, 1998; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2008; 78 FR 37146, June 20, 2013; 80 FR 75239, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.642 General standards.

(a) Each owner or operator of a source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the EPA has approved a State operating permit program under part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the source shall apply to the EPA Regional Office pursuant to part 71.

(b) The emission standards set forth in this subpart shall apply at all times.

(c) Table 6 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to this subpart.

(d) Initial performance tests and initial compliance determinations shall be required only as specified in this subpart.

(1) Performance tests and compliance determinations shall be conducted according to the schedule and procedures specified in this subpart.

(2) The owner or operator shall notify the Administrator of the intention to conduct a performance test at least 30 days before the performance test is scheduled.

(3) Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, an owner or operator shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. An owner or operator shall not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. The owner/operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(4) Data shall be reduced in accordance with the EPA-approved methods specified in the applicable section or, if other test methods are used, the data and methods shall be validated according to the protocol in Method 301 of appendix A of this part.

(e) All applicable records shall be maintained as specified in §63.655(i).

(f) All reports required under this subpart shall be sent to the Administrator at the addresses listed in §63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(g) The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the following equation:

$$E_A = 0.02\sum EPV_1 + \sum EPV_2 + 0.05\sum ES_1 + \sum ES_2 + \sum EGLR_{1C} + \sum EGLR_2 + (R) \sum EMV_1 + \sum EMV_2 + \sum EWW_{1C} + \sum EWW_2$$

where:

E_A = Emission rate, megagrams per year, allowed for the source.

$0.02\sum EPV_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in §63.641.

$\sum EPV_2$ = Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in §63.641.

$0.05\sum ES_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in §63.641.

$\sum ES_2$ = Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in §63.641.

$\sum EGLR_{1C}$ = Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in §63.641.

$\sum EGLR_2$ = Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in §63.641.

$(R)\sum EMV_1$ = Sum of the residual emissions megagrams per year, from all Group 1 marine tank vessels, as defined in §63.641.

R = 0.03 for existing sources, 0.02 for new sources.

$\sum EMV_2$ = Sum of the emissions, megagrams per year from all Group 2 marine tank vessels, as defined in §63.641.

ΣEWW_{ic} = Sum of the residual emissions from all Group 1 wastewater streams, as defined in §63.641. This term is calculated for each Group 1 stream according to the equation for EWW_{ic} in §63.652(h)(6).

ΣEWW_2 = Sum of emissions from all Group 2 wastewater streams, as defined in §63.641.

The emissions level represented by this equation is dependent on the collection of emission points in the source. The level is not fixed and can change as the emissions from each emission point change or as the number of emission points in the source changes.

(h) The owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k)(1) of this section.

(j) The owner or operator of a new source shall demonstrate compliance with the emission standard in paragraph (h) of this section only by following the procedures in paragraph (k) of this section. The owner or operator of a new source may not use the emissions averaging compliance approach.

(k) The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the applicable provisions in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as specified in §63.640(h).

(1) The owner or operator using this compliance approach shall also comply with the requirements of §§63.648 and/or 63.649, 63.654, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

(2) The owner or operator using this compliance approach is not required to calculate the annual emission rate specified in paragraph (g) of this section.

(l) The owner or operator of an existing source may elect to control some of the emission points within the source to different levels than specified under §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable according to §63.640(h), by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in paragraph (g) of this section. The owner or operator using emissions averaging shall meet the requirements in paragraphs (1)(1) and (2) of this section.

(1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in §63.652; and

(2) Comply with the requirements of §§63.648 and/or 63.649, 63.654, 63.652, 63.653, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

(m) A State may restrict the owner or operator of an existing source to using only the procedures in paragraph (k) of this section to comply with the emission standard in paragraph (g) of this section. Such a restriction would preclude the source from using an emissions averaging compliance approach.

(n) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29879, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75242, Dec. 1, 2015]

§63.643 Miscellaneous process vent provisions.

(a) The owner or operator of a Group 1 miscellaneous process vent as defined in §63.641 shall comply with the requirements of either paragraph (a)(1) or (2) of this section or, if applicable, paragraph (c) of this section. The owner or operator of a miscellaneous process vent that meets the conditions in paragraph (c) of this section is only required to comply with the requirements of paragraph (c) of this section and §63.655(g)(13) and (i)(12) for that vent.

(1) Reduce emissions of organic HAP's using a flare. On and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the requirements of §63.11(b) of subpart A or the requirements of §63.670.

(2) Reduce emissions of organic HAP's, using a control device, by 98 weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent. Compliance can be determined by measuring either organic HAP's or TOC's using the procedures in §63.645.

(b) If a boiler or process heater is used to comply with the percentage of reduction requirement or concentration limit specified in paragraph (a)(2) of this section, then the vent stream shall be introduced into the flame zone of such a device, or in a location such that the required percent reduction or concentration is achieved. Testing and monitoring is required only as specified in §§63.644(a) and 63.645 of this subpart.

(c) An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment

is emptied, depressurized, degassed or placed into service. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. The owner or operator must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent according to the compliance dates specified in table 11 of this subpart, unless an extension is requested in accordance with the provisions in §63.6(i).

(1) Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device, fuel gas system, or back to the process until one of the following conditions, as applicable, is met.

(i) The vapor in the equipment served by the maintenance vent has a lower explosive limit (LEL) of less than 10 percent.

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 psig or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) equipment is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 72 pounds of VOC.

(iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.*, hydrotreaters and hydrocrackers) at refineries that do not have a pure hydrogen supply, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent.

(2) Except for maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator shall determine mass of VOC in the equipment served by the maintenance vent based on the equipment size and contents after considering any contents drained or purged from the equipment. Equipment size may be determined from equipment design specifications. Equipment contents may be determined using process knowledge.

(d) After February 1, 2016 and prior to the date of compliance with the maintenance vent provisions in paragraph (c) of this section, the owner or operator must comply with the requirements in §63.642(n) for each maintenance venting event and maintain records necessary to demonstrate compliance with the requirements in §63.642(n) including, if appropriate, records of existing standard site procedures used to deinventory equipment for safety purposes.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75242, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.644 Monitoring provisions for miscellaneous process vents.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in §63.643(a) shall install the monitoring equipment specified in paragraph (a)(1), (2), (3), or (4) of this section, depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately and, except for CPMS installed for pilot flame monitoring, must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

(1) Where an incinerator is used, a temperature monitoring device equipped with a continuous recorder is required.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange occurs.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) Where a flare is used prior to January 30, 2019, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required, or the requirements of §63.670 shall be met. Where a flare is used on and after January 30, 2019, the requirements of §63.670 shall be met.

(3) Any boiler or process heater with a design heat input capacity greater than or equal to 44 megawatt or any boiler or process heater in which all vent streams are introduced into the flame zone is exempt from monitoring.

(4) Any boiler or process heater less than 44 megawatts design heat capacity where the vent stream is not introduced into the flame zone is required to use a temperature monitoring device in the firebox equipped with a continuous recorder.

(b) An owner or operator of a Group 1 miscellaneous process vent may request approval to monitor parameters other than those listed in paragraph (a) of this section. The request shall be submitted according to the procedures specified in §63.655(h). Approval shall be requested if the owner or operator:

(1) Uses a control device other than an incinerator, boiler, process heater, or flare; or

(2) Uses one of the control devices listed in paragraph (a) of this section, but seeks to monitor a parameter other than those specified in paragraph (a) of this section.

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a) shall comply with either paragraph (c)(1) or (2) of this section. Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream to the atmosphere or to a control device that does not comply with the requirements in §63.643(a) is an emissions standards violation. Equipment such as low leg drains and equipment subject to §63.648 are not subject to this paragraph (c).

(1) Install, calibrate and maintain a flow indicator that determines whether a vent stream flow is present at least once every hour. A manual block valve equipped with a valve position indicator may be used in lieu of a flow indicator, as long as the valve position indicator is monitored continuously. Records shall be generated as specified in §63.655(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the non-diverting position and that the vent stream is not diverted through the bypass line.

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.655(f)(3) shall be submitted in the Notification of Compliance Status report.

(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.655(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009; 80 FR 75243, Dec. 1, 2015]

§63.645 Test methods and procedures for miscellaneous process vents.

(a) To demonstrate compliance with §63.643, an owner or operator shall follow §63.116 except for §63.116 (a)(1), (d) and (e) of subpart G of this part except as provided in paragraphs (b) through (d) and paragraph (i) of this section.

(b) All references to §63.113(a)(1) or (a)(2) in §63.116 of subpart G of this part shall be replaced with §63.643(a)(1) or (a)(2), respectively.

(c) In §63.116(c)(4)(ii)(C) of subpart G of this part, organic HAP's in the list of HAP's in table 1 of this subpart shall be considered instead of the organic HAP's in table 2 of subpart F of this part.

(d) All references to §63.116(b)(1) or (b)(2) shall be replaced with paragraphs (d)(1) and (d)(2) of this section, respectively.

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

(2) Any boiler or process heater in which all vent streams are introduced into the flame zone.

(e) For purposes of determining the TOC emission rate, as specified under paragraph (f) of this section, the sampling site shall be after the last product recovery device (as defined in §63.641 of this subpart) (if any recovery devices are present) but prior to the inlet of any control device (as defined in §63.641 of this subpart) that is present, prior to any dilution of the process vent stream, and prior to release to the atmosphere.

(1) Methods 1 or 1A of 40 CFR part 60, appendix A-1, as appropriate, shall be used for selection of the sampling site. For vents smaller than 0.10 meter in diameter, sample at the center of the vent.

(2) No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.

(f) Except as provided in paragraph (g) of this section, an owner or operator seeking to demonstrate that a process vent TOC mass flow rate is less than 33 kilograms per day for an existing source or less than 6.8 kilograms per day for a new source in accordance with the Group 2 process vent definition of this subpart shall determine the TOC mass flow rate by the following procedures:

(1) The sampling site shall be selected as specified in paragraph (e) of this section.

(2) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, 2D, or 2F of 40 CFR part 60, appendix A-1 or Method 2G of 40 CFR part 60, appendix A-2, as appropriate.

(3) Method 18 or Method 25A of 40 CFR part 60, appendix A shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. If Method 25A is used, and the TOC mass flow rate calculated from the Method 25A measurement is greater than or equal to 33 kilograms per day for an existing source or 6.8 kilograms per day for a new source, Method 18 may be used to determine any non-VOC hydrocarbons that may be deducted to calculate the TOC (minus non-VOC hydrocarbons) concentration and mass flow rate. The following procedures shall be used to calculate parts per million by volume concentration:

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation if Method 18 is used:

$$C_{\text{TOC}} = \frac{\sum_{i=1}^x \left(\sum_{j=1}^n C_{ji} \right)}{X}$$

[View or download PDF](#)

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of the sample i , dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(4) The emission rate of TOC (minus methane and ethane) (E_{TOC}) shall be calculated using the following equation if Method 18 is used:

$$E = K_2 \left[\sum_{j=1}^n C_j M_j \right] Q_s$$

[View or download PDF](#)

where:

E = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2 = Constant, 5.986×10^{-5} (parts per million)⁻¹ (gram-mole per standard cubic meter) (kilogram per gram) (minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_j = Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section. C_j includes all organic compounds measured minus methane and ethane.

M_j = Molecular weight of organic compound j , gram per gram-mole.

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(5) If Method 25A is used, the emission rate of TOC (E_{TOC}) shall be calculated using the following equation:

$$E_{\text{TOC}} = K_2 C_{\text{TOC}} M Q_s$$

where:

E_{TOC} = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2 = Constant, 5.986×10^{-5} (parts per million)⁻¹ (gram-mole per standard cubic meter) (kilogram per gram)(minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_{TOC} = Concentration of TOC on a dry basis in parts per million volume as measured by Method 25A of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section.

M = Molecular weight of organic compound used to express units of C_{TOC} , gram per gram-mole.

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(g) Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate.

(1) Engineering assessment includes, but is not limited to, the following:

(i) Previous test results provided the tests are representative of current operating practices at the process unit.

(ii) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(iii) TOC emission rate specified or implied within a permit limit applicable to the process vent.

(iv) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(A) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(B) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities; and

(C) Estimation of TOC concentrations based on saturation conditions.

(v) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(h) The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based.

(1) The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in paragraphs (e) and (f) of this section, as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in paragraph (g) of this section.

(2) Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.655(f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640.

(i) A compliance determination for visible emissions shall be conducted within 150 days of the compliance date using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009; 80 FR 75243, Dec. 1, 2015]

§63.646 Storage vessel provisions.

Upon a demonstration of compliance with the standards in §63.660 by the compliance dates specified in §63.640(h), the standards in this section shall no longer apply.

(a) Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§63.119 through 63.121 except as provided in paragraphs (b) through (l) of this section.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in 40 CFR part 63, subparts A or G. The Group 1 storage vessel definition presented in §63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of §63.119 of subpart G of this part.

(1) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new

source, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street NW., 6th floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005-4070, (202) 682-8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.naesb.org>).

(c) The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: §63.119 (b)(5), (b)(6), (c)(2), and (d)(2).

(d) References shall apply as specified in paragraphs (d)(1) through (d)(10) of this section.

(1) All references to §63.100(k) of subpart F of this part (or the schedule provisions and the compliance date) shall be replaced with §63.640(h),

(2) All references to April 22, 1994 shall be replaced with August 18, 1995.

(3) All references to December 31, 1992 shall be replaced with July 15, 1994.

(4) All references to the compliance dates specified in §63.100 of subpart F shall be replaced with §63.640 (h) through (m).

(5) All references to §63.150 in §63.119 of subpart G of this part shall be replaced with §63.652.

(6) All references to §63.113(a)(2) of subpart G shall be replaced with §63.643(a)(2) of this subpart.

(7) All references to §63.126(b)(1) of subpart G shall be replaced with §63.422(b) of subpart R of this part.

(8) All references to §63.128(a) of subpart G shall be replaced with §63.425, paragraphs (a) through (c) and (e) through (h) of subpart R of this part.

(9) All references to §63.139(d)(1) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that 40 CFR 61.355 is applicable.

(10) All references to §63.139(c) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that §63.647 of this subpart is applicable.

(e) When complying with the inspection requirements of §63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals.

(f) The following paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:

(1) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

(2) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

(3) Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(g) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(h) References in §§63.119 through 63.121 to §63.122(g)(1), §63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in §63.120, paragraphs (d)(2) and (d)(3)(i) shall be replaced with the Notification of Compliance Status report.

(j) References to the Notification of Compliance Status report in §63.152(b) mean the Notification of Compliance Status required by §63.655(f).

(k) References to the Periodic Reports in §63.152(c) mean the Periodic Report required by §63.655(g).

(l) The State or local permitting authority can waive the notification requirements of §§63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §63.120(a)(6) or §63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 62 FR 7939, Feb. 21, 1997; 74 FR 55685, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 80 FR 75243, Dec. 1, 2015]

§63.647 Wastewater provisions.

(a) Except as provided in paragraphs (b) and (c) of this section, each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of this chapter for each process wastewater stream that meets the definition in §63.641.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in the Clean Air Act or in 40 CFR part 61, subpart FF, §61.341.

(c) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 61, subpart FF of this chapter, or the requirements of §63.670.

(d) Each owner or operator required under subpart FF of 40 CFR part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner consistent with the minimum or maximum (as appropriate) permitted concentration or operating parameter values. Operation of the process, treatment unit, or control device resulting in a measured concentration or operating parameter value outside the permitted limits shall constitute a violation of the emission standards. Failure to perform required leak monitoring for closed vent systems and control devices or failure to repair leaks within the time period specified in subpart FF of 40 CFR part 61 shall constitute a violation of the standard.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75244, Dec. 1, 2015]

§63.648 Equipment leak standards.

(a) Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60, subpart VV, and paragraph (b) of this section except as provided in paragraphs (a)(1) and (2), (c) through (i), and (j)(1) and (2) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) and (j)(1) and (2) of this section.

(1) For purposes of compliance with this section, the provisions of 40 CFR part 60, subpart VV apply only to equipment in organic HAP service, as defined in §63.641 of this subpart.

(2) Calculation of percentage leaking equipment components for subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(3) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 60, subpart VV of this chapter, or the requirements of §63.670.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 subpart VV or subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of paragraphs (b)(1) and (b)(2) of this section.

(1) Monitoring data must meet the test methods and procedures specified in §60.485(b) of 40 CFR part 60, subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part except for minor departures.

(2) Departures from the criteria specified in §60.485(b) of 40 CFR part 60 subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part or from the monitoring frequency specified in subpart VV or in paragraph (c) of this section (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H except as provided in paragraphs (c)(1) through (12) and (e) through (i) of this section.

(1) The instrument readings that define a leak for light liquid pumps subject to §63.163 of subpart H of this part and gas/vapor and light liquid valves subject to §63.168 of subpart H of this part are specified in table 2 of this subpart.

(2) In phase III of the valve standard, the owner or operator may monitor valves for leaks as specified in paragraphs (c)(2)(i) or (c)(2)(ii) of this section.

(i) If the owner or operator does not elect to monitor connectors, then the owner or operator shall monitor valves according to the frequency specified in table 8 of this subpart.

(ii) If an owner or operator elects to monitor connectors according to the provisions of §63.649, paragraphs (b), (c), or (d), then the owner or operator shall monitor valves at the frequencies specified in table 9 of this subpart.

(3) The owner or operator shall decide no later than the first required monitoring period after the phase I compliance date specified in §63.640(h) whether to calculate the percentage leaking valves on a process unit basis or on a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(4) The owner or operator shall decide no later than the first monitoring period after the phase III compliance date specified in §63.640(h) whether to monitor connectors according to the provisions in §63.649, paragraphs (b), (c), or (d).

(5) Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in §63.169 of subpart H of this part (except for the agitator provisions). The leak definition for valves, connectors, and instrumentation systems subject to §63.169 is 1,000 parts per million.

(6) In phase III of the pump standard, except as provided in paragraph (c)(7) of this section, owners or operators that achieve less than 10 percent of light liquid pumps leaking or three light liquid pumps leaking, whichever is greater, shall monitor light liquid pumps monthly.

(7) Owners or operators that achieve less than 3 percent of light liquid pumps leaking or one light liquid pump leaking, whichever is greater, shall monitor light liquid pumps quarterly.

(8) An owner or operator may make the election described in paragraphs (c)(3) and (c)(4) of this section at any time except that any election to change after the initial election shall be treated as a permit modification according to the terms of part 70 of this chapter.

(9) When complying with the requirements of §63.168(e)(3)(i), non-repairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and non-repairable. Otherwise, a number of non-repairable valves up to a maximum of 1 percent per year of the total number of valves in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percent leaking valves for subsequent monitoring periods. When the number of non-repairable valves exceeds 3 percent of the total number of valves in organic HAP service, the number of non-repairable valves exceeding 3 percent of the total number shall be included in the calculation of percent leaking valves.

(10) If in phase III of the valve standard any valve is designated as being leakless, the owner or operator has the option of following the provisions of 40 CFR 60.482-7(f). If an owner or operator chooses to comply with the provisions of 40 CFR 60.482-7(f), the valve is exempt from the valve monitoring provisions of §63.168 of subpart H of this part.

(11) [Reserved]

(12) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of §§63.172 and 63.180, or the requirements of §63.670.

(d) Upon startup of new sources, the owner or operator shall comply with §63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and §63.168(a)(1)(ii) of subpart H of this part for gas/vapor and light liquid valves.

(e) For reciprocating pumps in heavy liquid service and agitators in heavy liquid service, owners and operators are not required to comply with the requirements in §63.169 of subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from §§63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required.

(g) Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of this section if an owner or operator demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service.

(2) For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume.

(i) For purposes of determining the percentage hydrogen content in the process fluid that is contained in or contacts a compressor, the owner or operator shall use either:

(A) Procedures that conform to those specified in §60.593(b)(2) of 40 part 60, subpart GGG.

(B) Engineering judgment to demonstrate that the percentage content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume.

(I) When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(2) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in paragraph (g)(2)(i)(A) of this section.

(h) Each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years.

(i) Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required.

(j) Except as specified in paragraph (j)(4) of this section, the owner or operator must comply with the requirements specified in paragraphs (j)(1) and (2) of this section for pressure relief devices, such as relief valves or rupture disks, in organic HAP gas or vapor service instead of the pressure relief device requirements of §60.482-4 or §63.165, as applicable. Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator must also comply with the requirements specified in paragraph (j)(3) of this section for all pressure relief devices.

(1) *Operating requirements.* Except during a pressure release, operate each pressure relief device in organic HAP gas or vapor service with an instrument reading of less than 500 ppm above background as detected by Method 21 of 40 CFR part 60, appendix A-7.

(2) *Pressure release requirements.* For pressure relief devices in organic HAP gas or vapor service, the owner or operator must comply with the applicable requirements in paragraphs (j)(2)(i) through (iii) of this section following a pressure release.

(i) If the pressure relief device does not consist of or include a rupture disk, conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(ii) If the pressure relief device includes a rupture disk, either comply with the requirements in paragraph (j)(2)(i) of this section (not replacing the rupture disk) or install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator must conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(iii) If the pressure relief device consists only of a rupture disk, install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator may not initiate startup of the equipment served by the rupture disk until the rupture disk is replaced. The owner or operator must conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(3) *Pressure release management.* Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator shall comply with the requirements specified in paragraphs (j)(3)(i) through (v) of this section for all pressure relief devices in organic HAP service no later than January 30, 2019.

(i) The owner or operator must equip each affected pressure relief device with a device(s) or use a monitoring system that is capable of:

(A) Identifying the pressure release;

(B) Recording the time and duration of each pressure release; and

(C) Notifying operators immediately that a pressure release is occurring. The device or monitoring system may be either specific to the pressure relief device itself or may be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(ii) The owner or operator must apply at least three redundant prevention measures to each affected pressure relief device and document these measures. Examples of prevention measures include:

(A) Flow, temperature, level and pressure indicators with deadman switches, monitors, or automatic actuators.

(B) Documented routine inspection and maintenance programs and/or operator training (maintenance programs and operator training may count as only one redundant prevention measure).

(C) Inherently safer designs or safety instrumentation systems.

(D) Deluge systems.

(E) Staged relief system where initial pressure relief valve (with lower set release pressure) discharges to a flare or other closed vent system and control device.

(iii) If any affected pressure relief device releases to atmosphere as a result of a pressure release event, the owner or operator must perform root cause analysis and corrective action analysis according to the requirement in paragraph (j)(6) of this section and implement corrective actions according to the requirements in paragraph (j)(7) of this section. The owner or operator must also calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in §63.655(g)(10)(iii). Calculations may be based on data from the pressure relief device monitoring alone or in combination with process parameter monitoring data and process knowledge.

(iv) The owner or operator shall determine the total number of release events occurred during the calendar year for each affected pressure relief device separately. The owner or operator shall also determine the total number of release events for each pressure relief device for which the root cause analysis concluded that the root cause was a *force majeure* event, as defined in this subpart.

(v) Except for pressure relief devices described in paragraphs (j)(4) and (5) of this section, the following release events are a violation of the pressure release management work practice standards.

(A) Any release event for which the root cause of the event was determined to be operator error or poor maintenance.

(B) A second release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) A third release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for any reason.

(4) *Pressure relief devices routed to a control device.* If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is not required to comply with paragraph (j)(1), (2), or (3) (if applicable) of this section. Both the closed vent system and control device (if applicable) must meet the requirements of §63.644. When complying with this paragraph (j)(4),

all references to “Group 1 miscellaneous process vent” in §63.644 mean “pressure relief device.” If a pressure relief device complying with this paragraph (j)(4) is routed to the fuel gas system, then on and after January 30, 2019, any flares receiving gas from that fuel gas system must be in compliance with §63.670.

(5) *Pressure relief devices exempted from pressure release management requirements.* The following types of pressure relief devices are not subject to the pressure release management requirements in paragraph (j)(3) of this section.

(i) Pressure relief devices in heavy liquid service, as defined in §63.641.

(ii) Pressure relief devices that only release material that is liquid at standard conditions (1 atmosphere and 68 degrees Fahrenheit) and that are hard-piped to a controlled drain system (*i.e.*, a drain system meeting the requirements for Group 1 wastewater streams in §63.647(a)) or piped back to the process or pipeline.

(iii) Thermal expansion relief valves.

(iv) Pressure relief devices designed with a set relief pressure of less than 2.5 psig.

(v) Pressure relief devices that do not have the potential to emit 72 lbs/day or more of VOC based on the valve diameter, the set release pressure, and the equipment contents.

(vi) Pressure relief devices on mobile equipment.

(6) *Root cause analysis and corrective action analysis.* A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a release event. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (j)(6)(i) through (iv) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices installed on the same equipment to release.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices to release, regardless of the equipment served, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(iii) Except as provided in paragraphs (j)(6)(i) and (ii) of this section, if more than one pressure relief device has a release during the same time period, an initial root cause analysis shall be conducted separately for each pressure relief device that had a release. If the initial root cause analysis indicates that the release events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(7) *Corrective action implementation.* Each owner or operator required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (j)(3)(iii) and (j)(6) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (j)(7)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 80 FR 75244, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(a) If an owner or operator elects to monitor valves according to the provisions of §63.648(c)(2)(ii), the owner or operator shall implement one of the connector monitoring programs specified in paragraphs (b), (c), or (d) of this section.

(b) *Random 200 connector alternative.* The owner or operator shall implement a random sampling program for accessible connectors of 2.0 inches nominal diameter or greater. The program does not apply to inaccessible or unsafe-to-monitor connectors, as defined in §63.174 of subpart H. The sampling program shall be implemented source-wide.

(1) Within the first 12 months after the phase III compliance date specified in §63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.

(2) The instrument reading that defines a leak is 1,000 parts per million.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.

(5) After conducting the initial survey required in paragraph (b)(1) of this section, the owner or operator shall conduct subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall survey a random sample of 200 connectors once every 6 months.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall survey a random sample of 200 connectors once per year.

(iii) If the percentage leaking connectors is 0.5 percent or greater but less than 1.0 percent, the owner or operator shall survey a random sample of 200 connectors once every 2 years.

(iv) If the percentage leaking connectors is less than 0.5 percent, the owner or operator shall survey a random sample of 200 connectors once every 4 years.

(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(c) *Connector inspection alternative.* The owner or operator shall implement a program to monitor all accessible connectors in gas/vapor service that are 2.0 inches (nominal diameter) or greater and inspect all accessible connectors in light liquid service that are 2 inches (nominal diameter) or greater as described in paragraphs (c)(1) through (c)(7) of this section. The program does not apply to inaccessible or unsafe-to-monitor connectors.

(1) Within 12 months after the phase III compliance date specified in §63.640(h), all connectors in gas/vapor service shall be monitored using Method 21 of 40 CFR part 60 appendix A. The instrument reading that defines a leak is 1,000 parts per million.

(2) All connectors in light liquid service shall be inspected for leaks. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, connectors in gas/vapor service shall be monitored for leaks within the first 3 months after repair. Connectors in light liquid service shall be inspected for indications of leaks within the first 3 months after repair. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(5) After conducting the initial survey required in paragraphs (c)(1) and (c)(2) of this section, the owner or operator shall conduct subsequent monitoring at the frequencies specified in paragraphs (c)(5)(i) through (c)(5)(iii) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall monitor or inspect, as applicable, the connectors once per year.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 2 years.

(iii) If the percentage leaking connectors is less than 1.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 4 years.

(6) The percentage leaking connectors shall be calculated for connectors in gas/vapor service and for connectors in light liquid service. The data for the two groups of connectors shall not be pooled for the purpose of determining the percentage leaking connectors.

(i) The percentage leaking connectors shall be calculated as follows:

$$\% C_L = [(C_L - C_{AN}) / C_t + C_c] \times 100$$

where:

$\% C_L$ = Percentage leaking connectors.

C_L = Number of connectors including nonrepairables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, appendix A.

C_{AN} = Number of allowable nonrepairable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, C_t .

C_t = Total number of monitored connectors, including nonrepairables, in the process unit.

C_c = Optional credit for removed connectors = $0.67 \times$ net number (*i.e.*, the total number of connectors removed minus the total added) of connectors in organic HAP service removed from the process unit after the applicability date set forth in §63.640(h)(3)(iii) for existing process units, and after the date of start-up for new process units. If credits are not taken, then $C_c = 0$.

(ii) Nonrepairable connectors shall be included in the calculation of percentage leaking connectors the first time the connector is identified as leaking and nonrepairable. Otherwise, a number of nonrepairable connectors up to a maximum of 1 percent per year of the total number of connectors in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percentage leaking connectors for subsequent monitoring periods.

(iii) If the number of nonrepairable connectors exceeds 3 percent of the total number of connectors in organic HAP service, the number of nonrepairable connectors exceeding 3 percent of the total number shall be included in the calculation of the percentage leaking connectors.

(7) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(d) *Subpart H program.* The owner or operator shall implement a program to comply with the provisions in §63.174 of this part.

(e) Delay of repair of connectors for which leaks have been detected is allowed if repair is not technically feasible by normal repair techniques without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

(1) Delay of repair is allowed for equipment that is isolated from the process and that does not remain in organic HAP service.

(2) Delay of repair for connectors is also allowed if:

(i) The owner or operator determines that emissions of purged material resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, and

(ii) When repair procedures are accomplished, the purged material would be collected and destroyed or recovered in a control device.

(f) Any connector that is designated as an unsafe-to-repair connector is exempt from the requirements of paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), or (d) of this section if:

(1) The owner or operator determines that repair personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), of this section; or

(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(g) The owner or operator shall maintain records to document that the connector monitoring or inspections have been conducted as required and to document repair of leaking connectors as applicable.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75245, Dec. 1, 2015]

§63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a Group 1 gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall

comply with subpart R of this part, §§63.421, 63.422(a) through (c) and (e), 63.425(a) through (c) and (e) through (i), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k).

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart R. The §63.641 definition of “affected source” applies under this section.

(c) Gasoline loading racks regulated under this subpart are subject to the compliance dates specified in §63.640(h).

(d) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart R of this part, or the requirements of §63.670.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75245, Dec. 1, 2015]

§63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (e) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.568.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart Y. The §63.641 definition of “affected source” applies under this section.

(c) The notification reports under §63.567(b) are not required.

(d) The compliance time of 4 years after promulgation of 40 CFR part 63, subpart Y, does not apply. The compliance time is specified in §63.640(h)(1).

(e) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart Y of this part, or the requirements of §63.670.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek to comply with the emission standard in §63.642(g) by using emissions averaging according to §63.642(l) rather than following the provisions of §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and

63.651. Existing marine tank vessel loading operations located at the Valdez Marine Terminal source may not comply with the standard by using emissions averaging.

(b) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in §63.653(d) for all points to be included in an emissions average. The Implementation Plan shall identify all emission points to be included in the emissions average. This must include any Group 1 emission points to which the reference control technology (defined in §63.641) is not applied and all other emission points being controlled as part of the average.

(c) The following emission points can be used to generate emissions averaging credits if control was applied after November 15, 1990 and if sufficient information is available to determine the appropriate value of credits for the emission point:

(1) Group 2 emission points;

(2) Group 1 storage vessels, Group 1 wastewater streams, Group 1 gasoline loading racks, Group 1 marine tank vessels, and Group 1 miscellaneous process vents that are controlled by a technology that the Administrator or permitting authority agrees has a higher nominal efficiency than the reference control technology. Information on the nominal efficiencies for such technologies must be submitted and approved as provided in paragraph (i) of this section; and

(3) Emission points from which emissions are reduced by pollution prevention measures. Percentages of reduction for pollution prevention measures shall be determined as specified in paragraph (j) of this section.

(i) For a Group 1 emission point, the pollution prevention measure must reduce emissions more than the reference control technology would have had the reference control technology been applied to the emission point instead of the pollution prevention measure except as provided in paragraph (c)(3)(ii) of this section.

(ii) If a pollution prevention measure is used in conjunction with other controls for a Group 1 emission point, the pollution prevention measure alone does not have to reduce emissions more than the reference control technology, but the combination of the pollution prevention measure and other controls must reduce emissions more than the reference control technology would have had it been applied instead.

(d) The following emission points cannot be used to generate emissions averaging credits:

(1) Emission points already controlled on or before November 15, 1990 unless the level of control is increased after November 15, 1990, in which case credit will be allowed only for the increase in control after November 15, 1990;

(2) Group 1 emission points that are controlled by a reference control technology unless the reference control technology has been approved for use in a different manner and a higher nominal efficiency has been assigned according to the procedures in paragraph (i) of this section.

For example, it is not allowable to claim that an internal floating roof meeting only the specifications stated in the reference control technology definition in §63.641 (i.e., that meets the specifications of §63.119(b) of subpart G but does not have controlled fittings per §63.119 (b)(5) and (b)(6) of subpart G) applied to a storage vessel is achieving greater than 95 percent control;

(3) Emission points on shutdown process units. Process units that are shut down cannot be used to generate credits or debits;

(4) Wastewater that is not process wastewater or wastewater streams treated in biological treatment units. These two types of wastewater cannot be used to generate credits or debits. Group 1 wastewater streams cannot be left undercontrolled or uncontrolled to generate debits. For the purposes of this section, the terms “wastewater” and “wastewater stream” are used to mean process wastewater; and

(5) Emission points controlled to comply with a State or Federal rule other than this subpart, unless the level of control has been increased after November 15, 1990 above what is required by the other State or Federal rule. Only the control above what is required by the other State or Federal rule will be credited. However, if an emission point has been used to generate emissions averaging credit in an approved emissions average, and the point is subsequently made subject to a State or Federal rule other than this subpart, the point can continue to generate emissions averaging credit for the purpose of complying with the previously approved average.

(e) For all points included in an emissions average, the owner or operator shall:

(1) Calculate and record monthly debits for all Group 1 emission points that are controlled to a level less stringent than the reference control technology for those emission points. Equations in paragraph (g) of this section shall be used to calculate debits.

(2) Calculate and record monthly credits for all Group 1 or Group 2 emission points that are overcontrolled to compensate for the debits. Equations in paragraph (h) of this section shall be used to calculate credits. Emission points and controls that meet the criteria of paragraph (c) of this section may be included in the credit calculation, whereas those described in paragraph (d) of this section shall not be included.

(3) Demonstrate that annual credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same annual compliance period according to paragraph (g) of this section.

(i) The initial demonstration in the Implementation Plan that credit-generating emission points will be capable of generating sufficient credits to offset the debits from the debit-generating emission points must be made under representative operating conditions.

(ii) After the compliance date, actual operating data will be used for all debit and credit calculations.

(4) Demonstrate that debits calculated for a quarterly (3-month) period according to paragraph (g) of this section are not more than 1.30 times the credits for the same period calculated according to paragraph (h) of this section. Compliance for the quarter shall be determined based on the ratio of credits and debits from that quarter, with 30 percent more debits than credits allowed on a quarterly basis.

(5) Record and report quarterly and annual credits and debits in the Periodic Reports as specified in §63.655(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by §63.655(g)(8)(iii).

(f) Debits and credits shall be calculated in accordance with the methods and procedures specified in paragraphs (g) and (h) of this section, respectively, and shall not include emissions from the following:

(1) More than 20 individual emission points. Where pollution prevention measures (as specified in paragraph (j)(1) of this section) are used to control emission points to be included in an emissions average, no more than 25 emission points may be included in the average. For example, if two emission points to be included in an emissions average are controlled by pollution prevention measures, the average may include up to 22 emission points.

(2) Periods of startup, shutdown, and malfunction as described in the source's startup, shutdown, and malfunction plan required by §63.6(e)(3) of subpart A of this part.

(3) For emission points for which continuous monitors are used, periods of excess emissions as defined in §63.655(g)(6)(i). For these periods, the calculation of monthly credits and debits shall be adjusted as specified in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) No credits would be assigned to the credit-generating emission point.

(ii) Maximum debits would be assigned to the debit-generating emission point.

(iii) The owner or operator may use the procedures in paragraph (l) of this section to demonstrate to the Administrator that full or partial credits or debits should be assigned.

(g) Debits are generated by the difference between the actual emissions from a Group 1 emission point that is uncontrolled or is controlled to a level less stringent than the reference control technology, and the emissions allowed for Group 1 emission point. Debits shall be calculated as follows:

(1) The overall equation for calculating sourcewide debits is:

$$Debits = \sum_{i=1}^n (EPV_{iACTUAL} - (0.02) EPV_{iu}) + \sum_{i=1}^n (ES_{iACTUAL} - (0.05) ES_{iu}) + \sum_{i=1}^n (EGLR_{iACTUAL} - EGLR_{iC}) + \sum_{i=1}^n (EMV_{iACTUAL} - (0.03) EMV_{iu})$$

[View or download PDF](#)

where:

Debits and all terms of the equation are in units of megagrams per month, and

$EPV_{iACTUAL}$ = Emissions from each Group 1 miscellaneous process vent i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(2) of this section.

(0.02) EPV_{iu} = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(2) of this section.

$ES_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.

(0.05) ES_{iu} = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.

$EGLR_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(4) of this section.

$EGLR_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. This is calculated according to paragraph (g)(4) of this section.

$EMV_{iACTUAL}$ = Emissions from each Group 1 marine tank vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(5) of this section.

(0.03) EMV_{iu} = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions calculated according to paragraph (g)(5) of this section.

n = The number of Group 1 emission points being included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

(2) Emissions from miscellaneous process vents shall be calculated as follows:

(i) For purposes of determining miscellaneous process vent stream flow rate, organic HAP concentrations, and temperature, the sampling site shall be after the final product recovery device, if any recovery devices are present; before any control device (for miscellaneous process

vents, recovery devices shall not be considered control devices); and before discharge to the atmosphere. Method 1 or 1A of part 60, appendix A shall be used for selection of the sampling site.

(ii) The following equation shall be used for each miscellaneous process vent i to calculate EPV_{iu} :

$$EPV_{iu} = (2.494 \times 10^{-9}) Qh \left(\sum_{j=1}^n C_j M_j \right)$$

[View or download PDF](#)

where:

EPV_{iu} = Uncontrolled process vent emission rate from miscellaneous process vent i , megagrams per month.

Q = Vent stream flow rate, dry standard cubic meters per minute, measured using Methods 2, 2A, 2C, or 2D of part 60 appendix A, as appropriate.

h = Monthly hours of operation during which positive flow is present in the vent, hours per month.

C_j = Concentration, parts per million by volume, dry basis, of organic HAP j as measured by Method 18 of part 60 appendix A.

M_j = Molecular weight of organic HAP j , gram per gram-mole.

n = Number of organic HAP's in the miscellaneous process vent stream.

(A) The values of Q , C_j , and M_j shall be determined during a performance test conducted under representative operating conditions. The values of Q , C_j , and M_j shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

(B) If there is a change in capacity utilization other than a change in monthly operating hours, or if any other change is made to the process or product recovery equipment or operation such that the previously measured values of Q , C_j , and M_j are no longer representative, a new performance test shall be conducted to determine new representative values of Q , C_j , and M_j . These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following procedures and equations shall be used to calculate $EPV_{iACTUAL}$:

(A) If the vent is not controlled by a control device or pollution prevention measure, $EPV_{\text{ACTUAL}} = EPV_{\text{iu}}$, where EPV_{iu} is calculated according to the procedures in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the vent is controlled using a control device or a pollution prevention measure achieving less than 98-percent reduction,

$$EPV_{\text{ACTUAL}} = EPV_{\text{iu}} \times \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

(1) The percent reduction shall be measured according to the procedures in §63.116 of subpart G if a combustion control device is used. For a flare meeting the criteria in §63.116(a) of subpart G or §63.670, as applicable, or a boiler or process heater meeting the criteria in §63.645(d) or §63.116(b) of subpart G, the percentage of reduction shall be 98 percent. If a noncombustion control device is used, percentage of reduction shall be demonstrated by a performance test at the inlet and outlet of the device, or, if testing is not feasible, by a control design evaluation and documented engineering calculations.

(2) For determining debits from miscellaneous process vents, product recovery devices shall not be considered control devices and cannot be assigned a percentage of reduction in calculating EPV_{ACTUAL} . The sampling site for measurement of uncontrolled emissions is after the final product recovery device.

(3) Procedures for calculating the percentage of reduction of pollution prevention measures are specified in paragraph (j) of this section.

(3) Emissions from storage vessels shall be calculated as specified in §63.150(g)(3) of subpart G.

(4) Emissions from gasoline loading racks shall be calculated as follows:

(i) The following equation shall be used for each gasoline loading rack i to calculate $EGLR_{\text{iu}}$:

$$EGLR_{\text{iu}} = (1.20 \times 10^{-7}) \frac{SPMG}{T}$$

[View or download PDF](#)

where:

$EGLR_{\text{iu}}$ = Uncontrolled transfer HAP emission rate from gasoline loading rack i , megagrams per month

S = Saturation factor, dimensionless (see table 33 of subpart G).

P = Weighted average rack partial pressure of organic HAP's transferred at the rack during the month, kilopascals.

M = Weighted average molecular weight of organic HAP's transferred at the gasoline loading rack during the month, gram per gram-mole.

G = Monthly volume of gasoline transferred from gasoline loading rack, liters per month.

T = Weighted rack bulk liquid loading temperature during the month, degrees kelvin (degrees Celsius °C + 273).

(ii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack partial pressure:

$$P = \frac{\sum_{j=1}^{j=n} (P_j)(G_j)}{G}$$

[View or download PDF](#)

where:

P_j = Maximum true vapor pressure of individual organic HAP transferred at the rack, kilopascals.

G = Monthly volume of organic HAP transferred, liters per month, and

$$G = \sum_{j=1}^{j=n} G_j$$

[View or download PDF](#)

G_j = Monthly volume of individual organic HAP transferred at the gasoline loading rack, liters per month.

n = Number of organic HAP's transferred at the gasoline loading rack.

(iii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack molecular weight:

$$M = \frac{\sum_{j=1}^{j=n} (M_j)(G_j)}{G}$$

[View or download PDF](#)

where:

M_j = Molecular weight of individual organic HAP transferred at the rack, gram per gram-mole.

G , G_j , and n are as defined in paragraph (g)(4)(ii) of this section.

(iv) The following equation shall be used for each gasoline loading rack i to calculate the monthly weighted rack bulk liquid loading temperature:

$$T = \frac{\sum_{j=1}^{j=n} (T_j)(G_j)}{G}$$

[View or download PDF](#)

T_j = Average annual bulk temperature of individual organic HAP loaded at the gasoline loading rack, kelvin (degrees Celsius °C + 273).

G , G_j , and n are as defined in paragraph (g)(4)(ii) of this section.

(v) The following equation shall be used to calculate $EGLR_{ic}$:

$$EGLR_{ic} = 1 \times 10^{-8} G$$

[View or download PDF](#)

G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate $EGLR_{iACTUAL}$:

(A) If the gasoline loading rack is not controlled, $EGLR_{iACTUAL} = EGLR_{iu}$, where $EGLR_{iu}$ is calculated using the equations specified in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack is controlled using a control device or a pollution prevention measure not achieving the requirement of less than 10 milligrams of TOC per liter of gasoline loaded,

$$EGLR_{iACTUAL} = EGLR_{iu} \left(\frac{1 - \text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

(1) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.128(a) of subpart G. If testing is not feasible, the percentage of

reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(2) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(5) Emissions from marine tank vessel loading shall be calculated as follows:

(i) The following equation shall be used for each marine tank vessel i to calculate EMV_{iu} :

$$EMV_{iu} = \sum_{i=1}^m (Q_i)(F_i)(P_i)$$

[View or download PDF](#)

where:

EMV_{iu} = Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i , megagrams per month.

Q_i = Quantity of commodity loaded (per vessel type), liters.

F_i = Emission factor, megagrams per liter.

P_i = Percent HAP.

m = Number of combinations of commodities and vessel types loaded.

Emission factors shall be based on test data or emission estimation procedures specified in §63.565(l) of subpart Y.

(ii) The following procedures and equations shall be used to calculate $EMV_{iACTUAL}$:

(A) If the marine tank vessel is not controlled, $EMV_{iACTUAL} = EMV_{iu}$, where EMV_{iu} is calculated using the equations specified in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel is controlled using a control device or a pollution prevention measure achieving less than 97-percent reduction,

$$EMV_{iACTUAL} = EMV_{iu} \left(\frac{1 - \text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

(I) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.565(d) of subpart Y. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(2) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(h) Credits are generated by the difference between emissions that are allowed for each Group 1 and Group 2 emission point and the actual emissions from a Group 1 or Group 2 emission point that has been controlled after November 15, 1990 to a level more stringent than what is required by this subpart or any other State or Federal rule or statute. Credits shall be calculated as follows:

(1) The overall equation for calculating sourcewide credits is:

$$\begin{aligned} Credits = & D \sum_{i=1}^N \left((0.02) EPV1_{in} - EPV1_{iACTUAL} \right) + D \sum_{i=1}^M \left(EPV2_{iBASE} - EPV2_{iACTUAL} \right) + \\ & D \sum_{i=1}^N \left((0.05) ES1_{in} - ES1_{iACTUAL} \right) + D \sum_{i=1}^M \left(ES2_{iBASE} - ES2_{iACTUAL} \right) + \\ & D \sum_{i=1}^N \left(EGLR_{ik} - EGLR_{iACTUAL} \right) + D \sum_{i=1}^M \left(EGLR2_{iBASE} - EGLR2_{iACTUAL} \right) + \\ & D \sum_{i=1}^N \left((0.03) EMV1_{in} - EMV1_{iACTUAL} \right) + D \sum_{i=1}^M \left(EMV2_{iBASE} - EMV2_{iACTUAL} \right) + \\ & D \sum_{i=1}^N \left(EWW1_{ik} - EWW1_{iACTUAL} \right) + D \sum_{i=1}^M \left(EWW2_{iBASE} - EWW2_{iACTUAL} \right) \end{aligned}$$

[View or download PDF](#)

where:

Credits and all terms of the equation are in units of megagrams per month, the baseline date is November 15, 1990, and

D = Discount factor = 0.9 for all credit-generating emission points except those controlled by a pollution prevention measure, which will not be discounted.

$EPV1_{iACTUAL}$ = Emissions for each Group 1 miscellaneous process vent i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

(0.02) $EPV1_{in}$ = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions. $EPV1_{in}$ is calculated according to paragraph (h)(2) of this section.

$EPV2_{iBASE}$ = Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

$EPV2_{iACTUAL}$ = Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

$ES1_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

(0.05) $ES1_{iu}$ = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions. $ES1_{iu}$ is calculated according to paragraph (h)(3) of this section.

$ES2_{iACTUAL}$ = Emissions from each Group 2 storage vessel i that is controlled, calculated according to paragraph (h)(3) of this section.

$ES2_{iBASE}$ = Emissions from each Group 2 storage vessel i at the baseline date, as calculated in paragraph (h)(3) of this section.

$EGLR1_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

$EGLR1_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. $EGLR1_{iu}$ is calculated according to paragraph (h)(4) of this section.

$EGLR2_{iACTUAL}$ = Emissions from each Group 2 gasoline loading rack i that is controlled, calculated according to paragraph (h)(4) of this section.

$EGLR2_{iBASE}$ = Emissions from each Group 2 gasoline loading rack i at the baseline date, as calculated in paragraph (h)(4) of this section.

$EMV1_{iACTUAL}$ = Emissions from each Group 1 marine tank vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

(0.03) $EMV1_{iu}$ = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions. $EMV1_{iu}$ is calculated according to paragraph (h)(5) of this section.

$EMV2_{iACTUAL}$ = Emissions from each Group 2 marine tank vessel i that is controlled, calculated according to paragraph (h)(5) of this section.

$EMV2_{iBASE}$ = Emissions from each Group 2 marine tank vessel i at the baseline date, as calculated in paragraph (h)(5) of this section.

$EWV1_{iACTUAL}$ = Emissions from each Group 1 wastewater stream i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.

$EWV1_{ic}$ = Emissions from each Group 1 wastewater stream i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.

$EWV2_{iACTUAL}$ = Emissions from each Group 2 wastewater stream i that is controlled, calculated according to paragraph (h)(6) of this section.

$EWV2_{iBASE}$ = Emissions from each Group 2 wastewater stream i at the baseline date, calculated according to paragraph (h)(6) of this section.

n = Number of Group 1 emission points included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

m = Number of Group 2 emission points included in the emissions average. The value of m is not necessarily the same for each kind of emission point.

(i) For an emission point controlled using a reference control technology, the percentage of reduction for calculating credits shall be no greater than the nominal efficiency associated with the reference control technology, unless a higher nominal efficiency is assigned as specified in paragraph (h)(1)(ii) of this section.

(ii) For an emission point controlled to a level more stringent than the reference control technology, the nominal efficiency for calculating credits shall be assigned as described in paragraph (i) of this section. A reference control technology may be approved for use in a different manner and assigned a higher nominal efficiency according to the procedures in paragraph (i) of this section.

(iii) For an emission point controlled using a pollution prevention measure, the nominal efficiency for calculating credits shall be determined as described in paragraph (j) of this section.

(2) Emissions from process vents shall be determined as follows:

(i) Uncontrolled emissions from miscellaneous process vents, $EPV1_{iu}$, shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(ii) Actual emissions from miscellaneous process vents controlled using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving

greater than 98 percent emission reduction, $EPV1_{iACTUAL}$, shall be calculated according to the following equation:

$$EPV1_{iACTUAL} = EPV1_{iu} \left(1 - \frac{Nominal\ efficiency\ \%}{100\%} \right)$$

[View or download PDF](#)

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, $EPV2_{iACTUAL}$:

(A) For a Group 2 process vent controlled by a control device, a recovery device applied as a pollution prevention project, or a pollution prevention measure, if the control achieves a percentage of reduction less than or equal to a 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \times \left(1 - \frac{Percent\ reduction}{100\%} \right)$$

[View or download PDF](#)

(1) $EPV2_{iu}$ shall be calculated according to the equations and procedures for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section except as provided in paragraph (h)(2)(iii)(A)(3) of this section.

(2) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(2)(iii)(B)(1) through (g)(2)(iii)(B)(3) of this section except as provided in paragraph (h)(2)(iii)(A)(4) of this section.

(3) If a recovery device was added as part of a pollution prevention project, $EPV2_{iu}$ shall be calculated prior to that recovery device. The equation for EPV_{iu} in paragraph (g)(2)(ii) of this section shall be used to calculate $EPV2_{iu}$; however, the sampling site for measurement of vent stream flow rate and organic HAP concentration shall be at the inlet of the recovery device.

(4) If a recovery device was added as part of a pollution prevention project, the percentage of reduction shall be demonstrated by conducting a performance test at the inlet and outlet of that recovery device.

(B) For a Group 2 process vent controlled using a technology with an approved nominal efficiency greater than a 98 percent or a pollution prevention measure achieving greater than 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \left(1 - \frac{Nominal\ efficiency\ \%}{100\%} \right)$$

[View or download PDF](#)

(iv) Emissions from Group 2 process vents at baseline, $EPV2_{iBASE}$, shall be calculated as follows:

(A) If the process vent was uncontrolled on November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, and shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the process vent was controlled on November 15, 1990,

$$EPV2_{BASE} = EPV2_{iu} \left(1 - \frac{\text{Percent reduction}\%}{100\%} \right)$$

[View or download PDF](#)

where $EPV2_{iu}$ is calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section. The percentage of reduction shall be calculated according to the procedures specified in paragraphs (g)(2)(iii)(B)(1) through (g)(2)(iii)(B)(3) of this section.

(C) If a recovery device was added to a process vent as part of a pollution prevention project initiated after November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, where $EPV2_{iu}$ is calculated according to paragraph (h)(2)(iii)(A)(3) of this section.

(3) Emissions from storage vessels shall be determined as specified in §63.150(h)(3) of subpart G, except as follows:

(i) All references to §63.119(b) in §63.150(h)(3) of subpart G shall be replaced with: §63.119 (b) or §63.119(b) except for §63.119(b)(5) and (b)(6).

(ii) All references to §63.119(c) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(c) or §63.119(c) except for §63.119(c)(2).

(iii) All references to §63.119(d) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(d) or §63.119(d) except for §63.119(d)(2).

(4) Emissions from gasoline loading racks shall be determined as follows:

(i) Uncontrolled emissions from Group 1 gasoline loading racks, $EGLR1_{iu}$, shall be calculated according to the procedures and equations for $EGLR_{iu}$ as described in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(ii) Emissions from Group 1 gasoline loading racks if the reference control technology had been applied, $EGLR_{ic}$, shall be calculated according to the procedures and equations in paragraph (g)(4)(v) of this section.

(iii) Actual emissions from Group 1 gasoline loading racks controlled to less than 10 milligrams of TOC per liter of gasoline loaded; $EGLR_{iACTUAL}$, shall be calculated according to the following equation:

$$EGLR_{iACTUAL} = EGLR_{iW} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

[View or download PDF](#)

(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $EGLR_{iACTUAL}$:

(A) For a Group 2 gasoline loading rack controlled by a control device or a pollution prevention measure achieving emissions reduction but where emissions are greater than the 10 milligrams of TOC per liter of gasoline loaded requirement,

$$EGLR_{iACTUAL} = EGLR_{iW} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

(1) $EGLR_{iW}$ shall be calculated according to the equations and procedures for $EGLR_{iW}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(2) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(1) and (g)(4)(vi)(B)(2) of this section.

(B) For a Group 2 gasoline loading rack controlled by using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than a 98-percent reduction,

$$EGLR_{iACTUAL} = EGLR_{iW} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

[View or download PDF](#)

(v) Emissions from Group 2 gasoline loading racks at baseline, $EGLR_{iBASE}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $EGLR_{iBASE} = EGLR_{iW}$, and shall be calculated according to the procedures and equations for $EGLR_{iW}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack was controlled on November 15, 1990,

$$EGLR2_{iBASE} = EGLR2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

where $EGLR2_{iu}$ is calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(1) and (g)(4)(vi)(B)(2) of this section.

(5) Emissions from marine tank vessels shall be determined as follows:

(i) Uncontrolled emissions from Group 1 marine tank vessels, $EMV1_{iu}$, shall be calculated according to the procedures and equations for EMV_{iu} as described in paragraph (g)(5)(i) of this section.

(ii) Actual emissions from Group 1 marine tank vessels controlled using a technology or pollution prevention measure with an approved nominal efficiency greater than 97 percent, $EMV_{iACTUAL}$, shall be calculated according to the following equation:

$$EMV1_{iACTUAL} = EMV1_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

[View or download PDF](#)

(iii) The following procedures shall be used to calculate actual emissions from Group 2 marine tank vessels, $EMV2_{iACTUAL}$:

(A) For a Group 2 marine tank vessel controlled by a control device or a pollution prevention measure achieving a percentage of reduction less than or equal to 97 percent reduction,

$$EMV2_{iACTUAL} = EMV2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

(1) $EMV2_{iu}$ shall be calculated according to the equations and procedures for EMV_{iu} in paragraph (g)(5)(i) of this section.

(2) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(1) and (g)(5)(ii)(B)(2) of this section.

(B) For a Group 2 marine tank vessel controlled using a technology or a pollution prevention measure with an approved nominal efficiency greater than 97 percent,

$$EMV2_{ACTUAL} = EMV2_{iu} \left(1 - \frac{\text{Nominal efficiency}}{100\%} \right)$$

[View or download PDF](#)

(iv) Emissions from Group 2 marine tank vessels at baseline, $EMV2_{iBASE}$, shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, $EMV2_{iBASE}$ equals $EMV2_{iu}$, and shall be calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel was controlled on November 15, 1990,

$$EMV2_{iBASE} = EMV2_{iu} \left(1 - \frac{\text{Percent reduction}}{100\%} \right)$$

[View or download PDF](#)

where $EMV2_{iu}$ is calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(1) and (g)(5)(ii)(B)(2) of this section.

(6) Emissions from wastewater shall be determined as follows:

(i) For purposes of paragraphs (h)(4)(ii) through (h)(4)(vi) of this section, the following terms will have the meaning given them in paragraphs (h)(6)(i)(A) through (h)(6)(i)(C) of this section.

(A) *Correctly suppressed* means that a wastewater stream is being managed according to the requirements of §§61.343 through 61.347 or §61.342(c)(1)(iii) of 40 CFR part 61, subpart FF, as applicable, and the emissions from the waste management units subject to those requirements are routed to a control device that reduces HAP emissions by 95 percent or greater.

(B) *Treatment process* has the meaning given in §61.341 of 40 CFR part 61, subpart FF except that it does not include biological treatment units.

(C) *Vapor control device* means the control device that receives emissions vented from a treatment process or treatment processes.

(ii) The following equation shall be used for each wastewater stream i to calculate EWV_{ic} :

$$EWV_{ic} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 (1 - Fr_m) Fe_m HAP_{im} + (0.05) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 (Fr_m HAP_{im})$$

[View or download PDF](#)

where:

EW_{ic} = Monthly wastewater stream emission rate if wastewater stream i were controlled by the reference control technology, megagrams per month.

Q_i = Average flow rate for wastewater stream i , liters per minute.

H_i = Number of hours during the month that wastewater stream i was generated, hours per month.

Fr_m = Fraction removed of organic HAP m in wastewater, from table 7 of this subpart, dimensionless.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

s = Total number of organic HAP's in wastewater stream i .

HAP_{im} = Average concentration of organic HAP m in wastewater stream i , parts per million by weight.

(A) HAP_{im} shall be determined for the point of generation or at a location downstream of the point of generation. Wastewater samples shall be collected using the sampling procedures specified in Method 25D of 40 CFR part 60, appendix A. Where feasible, samples shall be taken from an enclosed pipe prior to the wastewater being exposed to the atmosphere. When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of organic HAP's prior to sampling. The samples collected may be analyzed by either of the following procedures:

(1) A test method or results from a test method that measures organic HAP concentrations in the wastewater, and that has been validated pursuant to section 5.1 or 5.3 of Method 301 of appendix A of this part may be used; or

(2) Method 305 of appendix A of this part may be used to determine C_{im} , the average volatile organic HAP concentration of organic HAP m in wastewater stream i , and then HAP_{im} may be calculated using the following equation: $HAP_{im} = C_{im}/Fm_m$, where Fm_m for organic HAP m is obtained from table 7 of this subpart.

(B) Values for Q_i , HAP_{im} , and C_{im} shall be determined during a performance test conducted under representative conditions. The average value obtained from three test runs shall be used. The values of Q_i , HAP_{im} , and C_{im} shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (h)(6)(i)(C) of this section.

(C) If there is a change to the process or operation such that the previously measured values of Q_i , HAP_{im} , and C_{im} are no longer representative, a new performance test shall be conducted to

determine new representative values of Q_i , HAP_{im} , and C_{im} . These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following equations shall be used to calculate $EWW1_{iACTUAL}$ for each Group 1 wastewater stream i that is correctly suppressed and is treated to a level more stringent than the reference control technology.

(A) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, and the vapor control device achieves a percentage of reduction equal to 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [Fe_m HAP_{im} (1 - PR_{im})] + 0.05 (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [HAP_{im} PR_{im}]$$

[View or download PDF](#)

Where:

$EWW1_{iACTUAL}$ = Monthly wastewater stream emission rate if wastewater stream i is treated to a level more stringent than the reference control technology, megagrams per month.

PR_{im} = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless, as calculated by:

$$PR_{im} = \frac{HAP_{im-in} - HAP_{im-out}}{HAP_{im-in}}$$

[View or download PDF](#)

Where:

HAP_{im-in} = Average concentration of organic HAP m , parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater entering the first treatment process in the series.

HAP_{im-out} = Average concentration of organic HAP m , parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater exiting the last treatment process in the series.

All other terms are as defined and determined in paragraph (h)(6)(ii) of this section.

(B) If the Group 1 wastewater stream i is not controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, but the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{ACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [Fe_m HAP_m (1 - A_m)] + \left(1 - \frac{\text{Nominal efficiency \%}}{100}\right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [HA$$

[View or download PDF](#)

Where:

Nominal efficiency = Approved reduction efficiency of the vapor control device, dimensionless, as determined according to the procedures in §63.652(i).

A_m = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless.

All other terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(1) If a steam stripper meeting the specifications in the definition of reference control technology for wastewater is used, A_m shall be equal to the value of Fr_m given in table 7 of this subpart.

(2) If an alternative control device is used, the percentage of reduction must be determined using the equation and methods specified in paragraph (h)(6)(iii)(A) of this section for determining PR_{im} . If the value of PR_{im} is greater than or equal to the value of Fr_m given in table 7 of this subpart, then A_m equals Fr_m unless a higher nominal efficiency has been approved. If a higher nominal efficiency has been approved for the treatment process, the owner or operator shall determine $EWW1_{ACTUAL}$ according to paragraph (h)(6)(iii)(B) of this section rather than paragraph (h)(6)(iii)(A) of this section. If PR_{im} is less than the value of FR_m given in table 7 of this subpart, emissions averaging shall not be used for this emission point.

(C) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated hazardous air pollutant that is greater than that specified in table 7 of this subpart, and the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{ACTUAL} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [Fe_m HAP_{im} (1 - PR_{im})] + \left(1 - \frac{\text{Nominal efficiency \%}}{100}\right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^5 [HA$$

[View or download PDF](#)

where all terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(iv) The following equation shall be used to calculate $EW\!W2_{iBASE}$ for each Group 2 wastewater stream i that on November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

$$EW\!W2_{iBASE} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s Fe_m HAP_{im}$$

[View or download PDF](#)

Where:

$EW\!W2_{iBASE}$ = Monthly wastewater stream emission rate if wastewater stream i is not correctly suppressed, megagrams per month.

Q_i , H_i , s , Fe_m , and HAP_{im} are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(v) The following equation shall be used to calculate $EW\!W2_{iBASE}$ for each Group 2 wastewater stream i on November 15, 1990 was correctly suppressed. $EW\!W2_{iBASE}$ shall be calculated as if the control methods being used on November 15, 1990 are in place and any control methods applied after November 15, 1990 are ignored. However, values for the parameters in the equation shall be representative of present production levels and stream properties.

$$EW\!W2_{iBASE} = (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [Fe_m HAP_{im} (1 - PR_{im})] + \left(1 - \frac{R_i}{100\%}\right) (6.0 \times 10^{-8}) Q_i H_i \sum_{m=1}^s [HAP_{im} PR_{im}]$$

[View or download PDF](#)

where R_i is calculated according to paragraph (h)(6)(vii) of this section and all other terms are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(vi) For Group 2 wastewater streams that are correctly suppressed, $EW\!W2_{iACTUAL}$ shall be calculated according to the equation for $EW\!W2_{iBASE}$ in paragraph (h)(6)(v) of this section. $EW\!W2_{iACTUAL}$ shall be calculated with all control methods in place accounted for.

(vii) The reduction efficiency, R_i , of the vapor control device shall be demonstrated according to the following procedures:

(A) Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate.

(B) The mass flow rate of organic compounds entering and exiting the control device shall be determined as follows:

(1) The time period for the test shall not be less than 3 hours during which at least three runs are conducted.

(2) A run shall consist of a 1-hour period during the test. For each run:

(i) The volume exhausted shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60 appendix A, as appropriate;

(ii) The organic concentration in the vent stream entering and exiting the control device shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(3) The mass flow rate of organic compounds entering and exiting the control device during each run shall be calculated as follows:

$$E_a = \frac{0.0416}{10^6 \times m} \left[\sum_{p=1}^m V_{ap} \left(\sum_{i=1}^n C_{ap} MW_i \right) \right]$$

$$E_b = \frac{0.0416}{10^6 \times m} \left[\sum_{p=1}^m V_{bp} \left(\sum_{i=1}^n C_{bp} MW_i \right) \right]$$

[View or download PDF](#)

Where:

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

V_{ap} = Average volumetric flow rate of vent stream exiting the control device during run p at standards conditions, cubic meters per hour.

V_{bp} = Average volumetric flow rate of vent stream entering the control device during run p at standards conditions, cubic meters per hour.

p = Run.

m = Number of runs.

C_{aip} = Concentration of organic compound i measured in the vent stream exiting the control device during run p as determined by Method 18 of 40 CFR part 60 appendix A, parts per million by volume on a dry basis.

C_{bip} = Concentration of organic compound i measured in the vent stream entering the control device during run p as determined by Method 18 of 40 CFR part 60, appendix A, parts per million by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, kilograms per kilogram-mole.

n = Number of organic compounds in the vent stream.

0.0416 = Conversion factor for molar volume, kilograms-mole per cubic meter at 293 kelvin and 760 millimeters mercury absolute.

(C) The organic reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

[View or download PDF](#)

Where:

R = Total organic reduction efficiency for the control device, percentage.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

(i) The following procedures shall be followed to establish nominal efficiencies. The procedures in paragraphs (i)(1) through (i)(6) of this section shall be followed for control technologies that are different in use or design from the reference control technologies and achieve greater percentages of reduction than the percentages of efficiency assigned to the reference control technologies in §63.641.

(1) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology, and the different control technology will be used in more than three applications at a single plant site, the owner or operator shall submit the information specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section to the Administrator in writing:

(i) Emission stream characteristics of each emission point to which the control technology is or will be applied including the kind of emission point, flow, organic HAP concentration, and all

other stream characteristics necessary to design the control technology or determine its performance;

(ii) Description of the control technology including design specifications;

(iii) Documentation demonstrating to the Administrator's satisfaction the control efficiency of the control technology. This may include performance test data collected using an appropriate EPA method or any other method validated according to Method 301 of appendix A of this part. If it is infeasible to obtain test data, documentation may include a design evaluation and calculations. The engineering basis of the calculation procedures and all inputs and assumptions made in the calculations shall be documented; and

(iv) A description of the parameter or parameters to be monitored to ensure that the control technology will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) The Administrator shall determine within 120 calendar days whether an application presents sufficient information to determine nominal efficiency. The Administrator reserves the right to request specific data in addition to the items listed in paragraph (i)(1) of this section.

(3) The Administrator shall determine within 120 calendar days of the submittal of sufficient data whether a control technology shall have a nominal efficiency and the level of that nominal efficiency. If, in the Administrator's judgment, the control technology achieves a level of emission reduction greater than the reference control technology for a particular kind of emission point, the Administrator will publish a FEDERAL REGISTER notice establishing a nominal efficiency for the control technology.

(4) The Administrator may grant conditional permission to take emission credits for use of the control technology on requirements that may be necessary to ensure operation and maintenance to achieve the specified nominal efficiency.

(5) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology and the different control technology will be used in no more than three applications at a single plant site, the information listed in paragraphs (i)(1)(i) through (i)(1)(iv) of this section can be submitted to the permitting authority for the source for approval instead of the Administrator.

(i) In these instances, use and conditions for use of the control technology can be approved by the permitting authority. The permitting authority shall follow the procedures specified in paragraphs (i)(2) through (i)(4) of this section except that, in these instances, a FEDERAL REGISTER notice is not required to establish the nominal efficiency for the different technology.

(ii) If, in reviewing the submittal, the permitting authority believes the control technology has broad applicability for use by other sources, the permitting authority shall submit the information provided in the application to the Director of the EPA Office of Air Quality Planning and Standards. The Administrator shall review the technology for broad applicability and may

publish a FEDERAL REGISTER notice; however, this review shall not affect the permitting authority's approval of the nominal efficiency of the control technology for the specific application.

(6) If, in reviewing an application for a control technology for an emission point, the Administrator or permitting authority determines the control technology is not different in use or design from the reference control technology, the Administrator or permitting authority shall deny the application.

(j) The following procedures shall be used for calculating the efficiency (percentage of reduction) of pollution prevention measures:

(1) A pollution prevention measure is any practice that meets the criteria of paragraphs (j)(1)(i) and (j)(1)(ii) of this section.

(i) A pollution prevention measure is any practice that results in a lesser quantity of organic HAP emissions per unit of product released to the atmosphere prior to out-of-process recycling, treatment, or control of emissions while the same product is produced.

(ii) Pollution prevention measures may include: Substitution of feedstocks that reduce HAP emissions, alterations to the production process to reduce the volume of materials released to the environment, equipment modifications; housekeeping measures, and in-process recycling that returns waste materials directly to production as raw materials. Production cutbacks do not qualify as pollution prevention.

(2) The emission reduction efficiency of pollution prevention measures implemented after November 15, 1990 can be used in calculating the actual emissions from an emission point in the debit and credit equations in paragraphs (g) and (h) of this section.

(i) For pollution prevention measures, the percentage of reduction used in the equations in paragraphs (g)(2) and (g)(3) of this section and paragraphs (h)(2) through (h)(4) of this section is the difference in percentage between the monthly organic HAP emissions for each emission point after the pollution prevention measure for the most recent month versus monthly emissions from the same emission point before the pollution prevention measure, adjusted by the volume of product produced during the two monthly periods.

(ii) The following equation shall be used to calculate the percentage of reduction of a pollution prevention measure for each emission point.

$$\text{Percent reduction} = \frac{E_B \frac{(E_{PP} \times P_B)}{P_{PP}}}{E_B} \times 100\%$$

[View or download PDF](#)

Where:

Percent reduction = Efficiency of pollution prevention measure (percentage of organic HAP reduction).

E_B = Monthly emissions before the pollution prevention measure, megagrams per month, determined as specified in paragraphs (j)(2)(ii)(A), (j)(2)(ii)(B), and (j)(2)(ii)(C) of this section.

E_{pp} = Monthly emissions after the pollution prevention measure, megagrams per month, as determined for the most recent month, determined as specified in paragraphs (j)(2)(ii)(D) or (j)(2)(ii)(E) of this section.

P_B = Monthly production before the pollution prevention measure, megagrams per month, during the same period over which E_B is calculated.

P_{pp} = Monthly production after the pollution prevention measure, megagrams per month, as determined for the most recent month.

(A) The monthly emissions before the pollution prevention measure, E_B , shall be determined in a manner consistent with the equations and procedures in paragraphs (g)(2), (g)(3), (g)(4), and (g)(5) of this section for miscellaneous process vents, storage vessels, gasoline loading racks, and marine tank vessels.

(B) For wastewater, E_B shall be calculated as follows:

$$E_B = \sum_{i=1}^n \left[\left(6.0 \times 10^{-9} \right) Q_{Bi} H_{Bi} \sum_{m=1}^s Fe_m HAP_{Em} \right]$$

[View or download PDF](#)

where:

n = Number of wastewater streams.

Q_{Bi} = Average flow rate for wastewater stream i before the pollution prevention measure, liters per minute.

H_{Bi} = Number of hours per month that wastewater stream i was discharged before the pollution prevention measure, hours per month.

s = Total number of organic HAP's in wastewater stream i .

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

HAP_{Bim} = Average concentration of organic HAP m in wastewater stream i, defined and determined according to paragraph (h)(6)(ii)(A)(2) of this section, before the pollution prevention measure, parts per million by weight, as measured before the implementation of the pollution measure.

(C) If the pollution prevention measure was implemented prior to July 14, 1994, records may be used to determine E_B .

(D) The monthly emissions after the pollution prevention measure, E_{pp} , may be determined during a performance test or by a design evaluation and documented engineering calculations. Once an emissions-to-production ratio has been established, the ratio can be used to estimate monthly emissions from monthly production records.

(E) For wastewater, E_{pp} shall be calculated using the following equation:

$$E_{pp} = \sum_{i=1}^n \left[(6.0 \times 10^{-8}) Q_{ppi} H_{ppi} \sum_{m=1}^s Fe_m HAP_{ppim} \right]$$

[View or download PDF](#)

where n, Q, H, s, Fe_m , and HAP are defined and determined as described in paragraph (j)(2)(ii)(B) of this section except that Q_{ppi} , H_{ppi} , and HAP_{ppim} shall be determined after the pollution prevention measure has been implemented.

(iii) All equations, calculations, test procedures, test results, and other information used to determine the percentage of reduction achieved by a pollution prevention measure for each emission point shall be fully documented.

(iv) The same pollution prevention measure may reduce emissions from multiple emission points. In such cases, the percentage of reduction in emissions for each emission point must be calculated.

(v) For the purposes of the equations in paragraphs (h)(2) through (h)(6) of this section used to calculate credits for emission points controlled more stringently than the reference control technology, the nominal efficiency of a pollution prevention measure is equivalent to the percentage of reduction of the pollution prevention measure. When a pollution prevention measure is used, the owner or operator of a source is not required to apply to the Administrator for a nominal efficiency and is not subject to paragraph (i) of this section.

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

(1) This demonstration of hazard or risk equivalency shall be made to the satisfaction of the State or local permitting authority.

(i) The State or local permitting authority may require owners and operators to use specific methodologies and procedures for making a hazard or risk determination.

(ii) The demonstration and approval of hazard or risk equivalency may be made according to any guidance that the EPA makes available for use.

(2) Owners and operators shall provide documentation demonstrating the hazard or risk equivalency of their proposed emissions average in their Implementation Plan.

(3) An emissions averaging plan that does not demonstrate an equivalent or lower hazard or risk to the satisfaction of the State or local permitting authority shall not be approved. The State or local permitting authority may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

(4) A hazard or risk equivalency demonstration shall:

(i) Be a quantitative, bona fide chemical hazard or risk assessment;

(ii) Account for differences in chemical hazard or risk to human health or the environment; and

(iii) Meet any requirements set by the State or local permitting authority for such demonstrations.

(1) For periods of excess emissions, an owner or operator may request that the provisions of paragraphs (1)(1) through (1)(4) of this section be followed instead of the procedures in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(1) The owner or operator shall notify the Administrator of excess emissions in the Periodic Reports as required in §63.655(g)(6).

(2) The owner or operator shall demonstrate that other types of monitoring data or engineering calculations are appropriate to establish that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits. This demonstration shall be made to the Administrator's satisfaction, and the Administrator may establish procedures for demonstrating compliance that are acceptable.

(3) The owner or operator shall provide documentation of the period of excess emissions and the other type of monitoring data or engineering calculations to be used to demonstrate that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits.

(4) The Administrator may assign full or partial credit and debits upon review of the information provided.

[60 FR 43260, Aug. 18, 1995; 60 FR 49976, Sept. 27, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29881, June 12, 1996; 61 FR 33799, June 28, 1996; 74 FR 55686, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

(a) For each emission point included in an emissions average, the owner or operator shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (7) of this section.

(1) The source shall implement the following testing, monitoring, recordkeeping, and reporting procedures for each miscellaneous process vent equipped with a flare, incinerator, boiler, or process heater:

(i) Conduct initial performance tests to determine the percentage of reduction as specified in §63.645 of this subpart and §63.116 of subpart G; and

(ii) Monitor the operating parameters specified in §63.644, as appropriate for the specific control device.

(2) The source shall implement the following procedures for each miscellaneous process vent, equipped with a carbon adsorber, absorber, or condenser but not equipped with a control device:

(i) Determine the flow rate and organic HAP concentration using the methods specified in §63.115 (a)(1) and (a)(2), §63.115 (b)(1) and (b)(2), and §63.115(c)(3) of subpart G; and

(ii) Monitor the operating parameters specified in §63.114 of subpart G, as appropriate for the specific recovery device.

(3) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:

(i) Perform the monitoring or inspection procedures in §63.646 and either §63.120 of subpart G or §63.1063 of subpart WW, as applicable; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in §63.646 and either §63.120(d) of subpart G or §63.985(b) of subpart SS, as applicable.

(4) For each gasoline loading rack that is controlled, perform the testing and monitoring procedures specified in §§63.425 and 63.427 of subpart R of this part except §63.425(d) or §63.427(c).

(5) For each marine tank vessel that is controlled, perform the compliance, monitoring, and performance testing, procedures specified in §§63.563, 63.564, and 63.565 of subpart Y of this part.

(6) The source shall implement the following procedures for wastewater emission points, as appropriate to the control techniques:

(i) For wastewater treatment processes, conduct tests as specified in §61.355 of subpart FF of part 60;

(ii) Conduct inspections and monitoring as specified in §§61.343 through 61.349 and §61.354 of 40 CFR part 61, subpart FF.

(7) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in §63.655(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by §63.655 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by §63.655.

(d) Each owner or operator of an existing source who elects to comply with §63.655(g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

(1) The Implementation Plan shall be submitted to the Administrator and approved prior to implementing emissions averaging. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, in a Notification of Compliance Status Report, in a Periodic Report or in any combination of these documents. If an owner or operator submits the information specified in paragraph (d)(2) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

(2) The Implementation Plan shall include the information specified in paragraphs (d)(2)(i) through (d)(2)(ix) of this section for all points included in the average.

(i) The identification of all emission points in the planned emissions average and notation of whether each emission point is a Group 1 or Group 2 emission point as defined in §63.641.

(ii) The projected annual emission debits and credits for each emission point and the sum for the emission points involved in the average calculated according to §63.652. The annual projected credits must be greater than the projected debits, as required under §63.652(e)(3).

(iii) The specific control technology or pollution prevention measure that will be used for each emission point included in the average and date of application or expected date of application.

(iv) The specific identification of each emission point affected by a pollution prevention measure. To be considered a pollution prevention measure, the criteria in §63.652(j)(1) must be met. If the same pollution prevention measure reduces or eliminates emissions from multiple emission points in the average, the owner or operator must identify each of these emission points.

(v) A statement that the compliance demonstration, monitoring, inspection, recordkeeping, and reporting provisions in paragraphs (a), (b), and (c) of this section that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

(vi) Documentation of the information listed in paragraphs (d)(2)(vi)(A) through (d)(2)(vi)(D) of this section for each emission point included in the average.

(A) The values of the parameters used to determine whether each emission point in the emissions average is Group 1 or Group 2.

(B) The estimated values of all parameters needed for input to the emission debit and credit calculations in §63.652 (g) and (h). These parameter values or, as appropriate, limited ranges for the parameter values, shall be specified in the source's Implementation Plan as enforceable operating conditions. Changes to these parameters must be reported in the next Periodic Report.

(C) The estimated percentage of reduction if a control technology achieving a lower percentage of reduction than the efficiency of the reference control technology, as defined in §63.641, is or will be applied to the emission point.

(D) The anticipated nominal efficiency if a control technology achieving a greater percentage emission reduction than the efficiency of the reference control technology is or will be applied to the emission point. The procedures in §63.652(i) shall be followed to apply for a nominal efficiency.

(vii) The information specified in §63.655(h)(4) for:

(A) Each miscellaneous process vent controlled by a pollution prevention measure or control technique for which monitoring parameters or inspection procedures are not specified in paragraphs (a)(1) or (a)(2) of this section; and

(B) Each storage vessel controlled by a pollution prevention measure or a control technique other than an internal or external floating roof or a closed vent system with a control device.

(viii) Documentation of the information listed in paragraphs (d)(2)(viii)(A) through (d)(2)(viii)(G) of this section for each process wastewater stream included in the average.

(A) The information used to determine whether the wastewater stream is a Group 1 or Group 2 wastewater stream.

(B) The estimated values of all parameters needed for input to the wastewater emission credit and debit calculations in §63.652(h)(6).

(C) The estimated percentage of reduction if the wastewater stream is or will be controlled using a treatment process or series of treatment processes that achieves an emission reduction less than or equal to the emission reduction specified in table 7 of this subpart.

(D) The estimated percentage of reduction if a control technology achieving less than or equal to 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(E) The estimated percentage of reduction if a pollution prevention measure is or will be applied.

(F) The anticipated nominal efficiency if the owner or operator plans to apply for a nominal efficiency under §63.652(i). A nominal efficiency shall be applied for if:

(1) A control technology is or will be applied to the wastewater stream and achieves an emission reduction greater than the emission reduction specified in table 7 of this subpart; or

(2) A control technology achieving greater than 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(G) For each pollution prevention measure, treatment process, or control device used to reduce air emissions of organic HAP from wastewater and for which no monitoring parameters or inspection procedures are specified in §63.647, the information specified in §63.655(h)(4) shall be included in the Implementation Plan.

(ix) Documentation required in §63.652(k) demonstrating the hazard or risk equivalency of the proposed emissions average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The Administrator shall either approve the Implementation Plan, request changes, or request that the owner or operator submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 31361, June 9, 1998; 74 FR 55686, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.654 Heat exchange systems.

(a) Except as specified in paragraph (b) of this section, the owner or operator of a heat exchange system that meets the criteria in §63.640(c)(8) must comply with the requirements of paragraphs (c) through (g) of this section.

(b) A heat exchange system is exempt from the requirements in paragraphs (c) through (g) of this section if all heat exchangers within the heat exchange system either:

(1) Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or

(2) Employ an intervening cooling fluid containing less than 5 percent by weight of total organic HAP, as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

(c) The owner or operator must perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements of this subpart according to the procedures in paragraphs (c)(1) through (6) of this section.

(1) *Monitoring locations for closed-loop recirculation heat exchange systems.* For each closed loop recirculating heat exchange system, collect and analyze a sample from the location(s) described in either paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Each cooling tower return line or any representative riser within the cooling tower prior to exposure to air for each heat exchange system.

(ii) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s).

(2) *Monitoring locations for once-through heat exchange systems.* For each once-through heat exchange system, collect and analyze a sample from the location(s) described in paragraph (c)(2)(i) of this section. The owner or operator may also elect to collect and analyze an additional sample from the location(s) described in paragraph (c)(2)(ii) of this section.

(i) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s). The selected monitoring location may be at a point where discharges from multiple heat exchange systems are combined provided that the combined cooling water flow rate at the monitoring location does not exceed 40,000 gallons per minute.

(ii) The inlet water feed line for a once-through heat exchange system prior to any heat exchanger. If multiple heat exchange systems use the same water feed (*i.e.*, inlet water from the same primary water source), the owner or operator may monitor at one representative location and use the monitoring results for that sampling location for all heat exchange systems that use that same water feed.

(3) *Monitoring method.* Determine the total strippable hydrocarbon concentration (in parts per million by volume (ppmv) as methane) at each monitoring location using the “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) using a flame ionization detector (FID) analyzer for on-site determination as described in Section 6.1 of the Modified El Paso Method.

(4) *Monitoring frequency and leak action level for existing sources.* For a heat exchange system at an existing source, the owner or operator must comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(i) of this section or comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(ii) of this section. The owner or operator of an affected heat exchange system may choose to comply with paragraph (c)(4)(i) of this section for some heat exchange systems at the petroleum refinery and comply with paragraph (c)(4)(ii) of this section for other heat exchange systems. However, for each affected heat exchange system, the owner or operator of an affected heat exchange system must elect one monitoring alternative that will apply at all times. If the owner or operator intends to change the monitoring alternative that applies to a heat exchange system, the owner or operator must notify the Administrator 30 days in advance of such a change. All “leaks” identified prior to changing monitoring alternatives must be repaired. The monitoring frequencies specified in paragraphs (c)(4)(i) and (ii) of this section also apply to the inlet water feed line for a once-through heat exchange system, if monitoring of the inlet water feed is elected as provided in paragraph (c)(2)(ii) of this section.

(i) Monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 6.2 ppmv.

(ii) Monitor quarterly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv unless repair is delayed as provided in paragraph (f) of this section. If a repair is delayed as provided in paragraph (f) of this section, monitor monthly.

(5) *Monitoring frequency and leak action level for new sources.* For a heat exchange system at a new source, the owner or operator must monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv.

(6) *Leak definition.* A leak is defined as described in paragraph (c)(6)(i) or (c)(6)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, a leak is detected if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the leak action level.

(ii) For all other heat exchange systems, a leak is detected if a measurement value of the sample taken from a location specified in either paragraph (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the leak action level.

(d) If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs (e) and (f) of this section. Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph (c)(3) of this section to verify that the measured concentration is below the applicable action level. Actions that can be taken to achieve repair include but are not limited to:

(1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(2) Blocking the leaking tube within the heat exchanger;

(3) Changing the pressure so that water flows into the process fluid;

(4) Replacing the heat exchanger or heat exchanger bundle; or

(5) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(e) If the owner or operator detects a leak when monitoring a cooling tower return line under paragraph (c)(1)(i) of this section, the owner or operator may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected as provided under paragraph (c)(1)(ii) of this section. If no leaks are detected when monitoring according to the requirements of paragraph (c)(1)(ii) of this section, the heat exchange system is considered to meet the repair requirements through re-monitoring of the heat exchange system as provided in paragraph (d) of this section.

(f) The owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in paragraph (f)(1) or (f)(2) of this section is met and the leak is less than the delay of repair action level specified in paragraph (f)(3) of this section. The owner or operator must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.

(1) If the repair is technically infeasible without a shutdown and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly

monitoring periods during the delay of repair, the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(2) If the necessary equipment, parts, or personnel are not available and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay the repair for a maximum of 120 calendar days. The owner or operator must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(3) The delay of repair action level is a total strippable hydrocarbon concentration (as methane) in the stripping gas of 62 ppmv. The delay of repair action level is assessed as described in paragraph (f)(3)(i) or (f)(3)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, the delay of repair action level is exceeded if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the delay of repair action level.

(ii) For all other heat exchange systems, the delay of repair action level is exceeded if a measurement value of the sample taken from a location specified in either paragraphs (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the delay of repair action level.

(g) To delay the repair under paragraph (f) of this section, the owner or operator must record the information in paragraphs (g)(1) through (4) of this section.

(1) The reason(s) for delaying repair.

(2) A schedule for completing the repair as soon as practical.

(3) The date and concentration of the leak as first identified and the results of all subsequent monthly monitoring events during the delay of repair.

(4) An estimate of the potential strippable hydrocarbon emissions from the leaking heat exchange system or heat exchanger for each required delay of repair monitoring interval following the procedures in paragraphs (g)(4)(i) through (iv) of this section.

(i) Determine the leak concentration as specified in paragraph (c) of this section and convert the stripping gas leak concentration (in ppmv as methane) to an equivalent liquid concentration, in

parts per million by weight (ppmw), using equation 7-1 from “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) and the molecular weight of 16 grams per mole (g/mol) for methane.

(ii) Determine the mass flow rate of the cooling water at the monitoring location where the leak was detected. If the monitoring location is an individual cooling tower riser, determine the total cooling water mass flow rate to the cooling tower. Cooling water mass flow rates may be determined using direct measurement, pump curves, heat balance calculations, or other engineering methods. Volumetric flow measurements may be used and converted to mass flow rates using the density of water at the specific monitoring location temperature or using the default density of water at 25 degrees Celsius, which is 997 kilograms per cubic meter or 8.32 pounds per gallon.

(iii) For delay of repair monitoring intervals prior to repair of the leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the monitoring interval by multiplying the leak concentration in the cooling water, ppmw, determined in (g)(4)(i) of this section, by the mass flow rate of the cooling water determined in (g)(4)(ii) of this section and by the duration of the delay of repair monitoring interval. The duration of the delay of repair monitoring interval is the time period starting at midnight on the day of the previous monitoring event or at midnight on the day the repair would have had to be completed if the repair had not been delayed, whichever is later, and ending at midnight of the day the of the current monitoring event.

(iv) For delay of repair monitoring intervals ending with a repaired leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the final delay of repair monitoring interval by multiplying the duration of the final delay of repair monitoring interval by the leak concentration and cooling water flow rates determined for the last monitoring event prior to the re-monitoring event used to verify the leak was repaired. The duration of the final delay of repair monitoring interval is the time period starting at midnight of the day of the last monitoring event prior to re-monitoring to verify the leak was repaired and ending at the time of the re-monitoring event that verified that the leak was repaired.

[74 FR 55686, Oct. 28, 2009, as amended at 75 FR 37731, June 30, 2010; 78 FR 37146, June 20, 2013]

§63.655 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to the wastewater provisions in §63.647 shall comply with the recordkeeping and reporting provisions in §§61.356 and 61.357 of 40 CFR part 61, subpart FF unless they are complying with the wastewater provisions specified in paragraph (o)(2)(ii) of §63.640. There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and

reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(b) Each owner or operator subject to the gasoline loading rack provisions in §63.650 shall comply with the recordkeeping and reporting provisions in §63.428 (b) and (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(c) Each owner or operator subject to the marine tank vessel loading operation standards in §63.651 shall comply with the recordkeeping and reporting provisions in §§63.567(a) and 63.567(c) through (k) of subpart Y. These requirements are summarized in table 5 of this subpart. There are no additional reporting and recordkeeping requirements for marine tank vessel loading operations under this subpart unless marine tank vessel loading operations are included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(d) Each owner or operator subject to the equipment leaks standards in §63.648 shall comply with the recordkeeping and reporting provisions in paragraphs (d)(1) through (d)(6) of this section.

(1) Sections 60.486 and 60.487 of subpart VV of part 60 except as specified in paragraph (d)(1)(i) of this section; or §§63.181 and 63.182 of subpart H of this part except for §§63.182(b), (c)(2), and (c)(4).

(i) The signature of the owner or operator (or designate) whose decision it was that a repair could not be effected without a process shutdown is not required to be recorded. Instead, the name of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years.

(ii) [Reserved]

(2) The Notification of Compliance Status report required by §63.182(c) of subpart H and the initial semiannual report required by §60.487(b) of 40 CFR part 60, subpart VV shall be submitted within 150 days of the compliance date specified in §63.640(h); the requirements of subpart H of this part are summarized in table 3 of this subpart.

(3) An owner or operator who determines that a compressor qualifies for the hydrogen service exemption in §63.648 shall also keep a record of the demonstration required by §63.648.

(4) An owner or operator must keep a list of identification numbers for valves that are designated as leakless per §63.648(c)(10).

(5) An owner or operator must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart.

(6) An owner or operator must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per §§63.648 (f) and (i).

(e) Each owner or operator of a source subject to this subpart shall submit the reports listed in paragraphs (e)(1) through (e)(3) of this section except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.

(1) A Notification of Compliance Status report as described in paragraph (f) of this section;

(2) Periodic Reports as described in paragraph (g) of this section; and

(3) Other reports as described in paragraph (h) of this section.

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in §63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with §63.640(l)(3) and for storage vessels subject to the compliance schedule specified in §63.640(h)(2). Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) shall be submitted according to paragraph (f)(6) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in §63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in §63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each owner or operator of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by subpart R of this part within 150 days after the compliance dates specified in §63.640(h).

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (viii) of this section.

(i) For storage vessels, this report shall include the information specified in paragraphs (f)(1)(i)(A) through (f)(1)(i)(D) of this section.

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in paragraphs (f)(1)(i)(A)(1) through (3) of this section. This information is to be revised each time a Notification of Compliance Status

report is submitted for a storage vessel subject to the compliance schedule specified in §63.640(h)(2) or to comply with §63.640(l)(3).

(1) For each Group 1 storage vessel complying with §63.646 that is not included in an emissions average, the method of compliance (i.e., internal floating roof, external floating roof, or closed vent system and control device).

(2) For storage vessels subject to the compliance schedule specified in §63.640(h)(2) that are not complying with §63.646, the anticipated compliance date.

(3) For storage vessels subject to the compliance schedule specified in §63.640(h)(2) that are complying with §63.646 and the Group 1 storage vessels described in §63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with §63.646 or §63.660, the owner or operator shall submit:

(1) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed; and either

(2) The design evaluation documentation specified in §63.120(d)(1)(i) of subpart G or §63.985(b)(1)(i) of subpart SS (as applicable), if the owner or operator elects to prepare a design evaluation; or

(3) If the owner or operator elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the owner or operator shall submit:

(1) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(2) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the owner or operator shall submit:

(1) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

(2) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.120(e) of subpart G or §63.987(b) of subpart SS or §63.670(h), as applicable; and

(3) All periods during the compliance determination when the pilot flame is absent.

(ii) For miscellaneous process vents, identification of each miscellaneous process vent subject to this subpart, whether the process vent is Group 1 or Group 2, and the method of compliance for each Group 1 miscellaneous process vent that is not included in an emissions average (e.g., use of a flare or other control device meeting the requirements of §63.643(a)).

(iii) For miscellaneous process vents controlled by control devices required to be tested under §63.645 of this subpart and §63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in §63.645 and that the test conditions are representative of current operating conditions.

(A) The percentage of reduction of organic HAP's or TOC, or the outlet concentration of organic HAP's or TOC (parts per million by volume on a dry basis corrected to 3 percent oxygen), determined as specified in §63.116(c) of subpart G of this part; and

(B) The value of the monitored parameters specified in table 10 of this subpart, or a site-specific parameter approved by the permitting authority, averaged over the full period of the performance test,

(iv) For miscellaneous process vents controlled by flares, initial compliance test results including the information in paragraphs (f)(1)(iv)(A) and (B) of this section.

(A) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §§63.645 and 63.116(a) of subpart G or §63.670(h), as applicable; and

(B) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(v) For equipment leaks complying with §63.648(c) (i.e., complying with the requirements of subpart H of this part), the Notification of Compliance Report Status report information required by §63.182(c) of subpart H and whether the percentage of leaking valves will be reported on a process unit basis or a sourcewide basis.

(vi) For each heat exchange system, identification of the heat exchange systems that are subject to the requirements of this subpart. For heat exchange systems at existing sources, the owner or operator shall indicate whether monitoring will be conducted as specified in §63.654(c)(4)(i) or §63.654(c)(4)(ii).

(vii) For pressure relief devices in organic HAP service subject to the requirements in §63.648(j)(3)(i) and (ii), this report shall include the information specified in paragraphs (f)(1)(vii)(A) and (B) of this section.

(A) A description of the monitoring system to be implemented, including the relief devices and process parameters to be monitored, and a description of the alarms or other methods by which operators will be notified of a pressure release.

(B) A description of the prevention measures to be implemented for each affected pressure relief device.

(viii) For each delayed coking unit, identification of whether the unit is an existing affected source or a new affected source and whether monitoring will be conducted as specified in §63.657(b) or (c).

(2) If initial performance tests are required by §§63.643 through 63.653, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source. On and after February 1, 2016, performance tests shall be submitted according to paragraph (h)(9) of this section.

(i) For additional tests performed using the same method, the results specified in paragraph (f)(1) of this section shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) Performance tests are required only if specified by §§63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required.

(3) For each monitored parameter for which a range is required to be established under §63.120(d) of subpart G or §63.985(b) of subpart SS for storage vessels or §63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (iii) of this section.

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering

assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for input to the emission credit and debit equations in §63.652(g) and (h), calculated or measured according to the procedures in §63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in §63.640.

(6) Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in paragraph (g) of this section. The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1) through (f)(5) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(g) The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the information specified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section is collected. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the events identified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other

regulations in place of or as part of the Periodic Report required by this paragraph (g) if the reports contain the information required by paragraphs (g)(1) through (14) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraphs (g)(2) through (5) of this section. Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with §63.646.

(2) *Internal floating roofs.* (i) An owner or operator who elects to comply with §63.646 by using a fixed roof and an internal floating roof or by using an external floating roof converted to an internal floating roof shall submit the results of each inspection conducted in accordance with §63.120(a) of subpart G in which a failure is detected in the control equipment.

(A) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G, the specifications and requirements listed in paragraphs (g)(2)(i)(A)(1) through (3) of this section apply.

(1) A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

(2) Except as provided in paragraph (g)(2)(i)(A)(3) of this section, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

(3) If an extension is utilized in accordance with §63.120(a)(4) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(a)(4) of subpart G; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(B) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G (*i.e.*, internal inspections), the specifications and requirements listed in paragraphs (g)(2)(i)(B)(1) and (2) of this section apply.

(1) A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than a 10 percent open.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with §63.660 by using a fixed roof and an internal floating roof shall submit the results of each inspection conducted in accordance with §63.1063(c)(1), (d)(1), and (d)(2) of subpart WW in which a failure is detected in the control equipment. For vessels for which inspections are required under §63.1063(c) and (d), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) through (C) of this section apply.

(A) A failure is defined in §63.1063(d)(1) of subpart WW.

(B) Each Periodic Report shall include a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs.

(C) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) of subpart WW shall, in the next Periodic Report, submit the documentation required by §63.1063(e)(2).

(3) *External floating roofs.* (i) An owner or operator who elects to comply with §63.646 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i)(A) through (C) of this section.

(A) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with §63.120(b) of subpart G in which the seal and seal gap requirements of §63.120(b)(3), (4), (5), or (6) of subpart G are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A)(1) through (4) of this section.

(1) The date of the seal gap measurement.

(2) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (4) of subpart G.

(3) A description of any seal condition specified in §63.120(b)(5) or (6) of subpart G that is not met.

(4) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(B) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(b)(7)(ii) or (b)(8) of subpart G, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(C) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by §63.120(b)(10) of subpart G. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(i)(C)(1) and (2) of this section.

(1) A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or, for a storage vessel that is part of a new source, the gaskets no longer close off the liquid surface from the atmosphere; or, for a storage vessel that is part of a new source, the slotted membrane has more than 10 percent open area.

(2) Each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

(ii) An owner or operator who elects to comply with §63.660 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(ii)(A) and (B) of this section.

(A) For vessels for which inspections are required under §63.1063(c)(2), (d)(1), and (d)(3) of subpart WW, the owner or operator shall submit, as part of the Periodic Report, a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs. A failure is defined in §63.1063(d)(1).

(B) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or (c)(2)(iv)(B) of subpart WW shall, in the next Periodic Report, submit the documentation required by those paragraphs.

(4) [Reserved]

(5) An owner or operator who elects to comply with §63.646 or §63.660 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(5)(i) through (v) of this section, as applicable.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of either §63.119(e)(1) or (2) of subpart G, §63.985(a) and (b) of subpart SS, or §63.670, as applicable.

(A) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description shall include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(B) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description shall include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the

requirements of either §63.119(e)(1) or (2) of subpart G, §63.985(a) and (b) of subpart SS, or §63.670, as applicable, due to planned routine maintenance.

(ii) If a control device other than a flare is used, the Periodic Report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance Status report. The description shall include: Identification of the control device for which the measured parameters were outside of the established ranges, and causes for the measured parameters to be outside of the established ranges.

(iii) If a flare is used prior to January 30, 2019 and prior to electing to comply with the requirements in §63.670, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in §63.11(b) of subpart A and shall include: Identification of the flare that does not meet the general requirements specified in §63.11(b) of subpart A, and reasons the flare did not meet the general requirements specified in §63.11(b) of subpart A.

(iv) If a flare is used on or after the date for which compliance with the requirements in §63.670 is elected, which can be no later than January 30, 2019, the Periodic Report shall include the items specified in paragraph (g)(11) of this section.

(v) An owner or operator who elects to comply with §63.660 by installing an alternate control device as described in §63.1064 of subpart WW shall submit, as part of the next Periodic Report, a written application as described in §63.1066(b)(3) of subpart WW.

(6) For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards.

(i) Period of excess emission means any of the following conditions:

(A) An operating day when the daily average value of a monitored parameter, except presence of a flare pilot flame, is outside the range specified in the Notification of Compliance Status report. Monitoring data recorded during periods of monitoring system breakdown, repairs, calibration checks and zero (low-level) and high-level adjustments shall not be used in computing daily average values of monitored parameters.

(B) An operating day when all pilot flames of a flare are absent.

(C) An operating day when monitoring data required to be recorded in paragraphs (i)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems under paragraph (h)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) For periods in closed vent systems when a Group 1 miscellaneous process vent stream was detected in the bypass line or diverted from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), report the date, time, duration, estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP that bypassed the control device. For periods when the flow indicator is not operating, report the date, time, and duration.

(7) If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report.

(i) Results of the performance test shall include the identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

(ii) The complete test report shall be maintained onsite.

(8) The owner or operator of a source shall submit quarterly reports for all emission points included in an emissions average.

(i) The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in §63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in paragraphs (g)(2) through (g)(7) of this section for all storage vessels and miscellaneous process vents included in an emissions average;

(B) The information required to be reported by §63.428 (h)(1), (h)(2), and (h)(3) for each gasoline loading rack included in an emissions average, unless this information has already been submitted in a separate report;

(C) The information required to be reported by §63.567(e)(4) and (j)(3) of subpart Y for each marine tank vessel loading operation included in an emissions average, unless the information has already been submitted in a separate report;

(D) Any information pertaining to each wastewater stream included in an emissions average that the source is required to report under the Implementation Plan for the source;

(E) The credits and debits calculated each month during the quarter;

(F) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under §§63.652(e)(4);

(G) The values of any inputs to the credit and debit equations in §63.652 (g) and (h) that change from month to month during the quarter or that have changed since the previous quarter; and

(H) Any other information the source is required to report under the Implementation Plan for the source.

(iii) Every fourth quarterly report shall include the following:

(A) A demonstration that annual credits are greater than or equal to annual debits as required by §63.652(e)(3); and

(B) A certification of compliance with all the emissions averaging provisions in §63.652 of this subpart.

(9) For heat exchange systems, Periodic Reports must include the following information:

(i) The number of heat exchange systems at the plant site subject to the monitoring requirements in §63.654.

(ii) The number of heat exchange systems at the plant site found to be leaking.

(iii) For each monitoring location where the total strippable hydrocarbon concentration was determined to be equal to or greater than the applicable leak definitions specified in §63.654(c)(6), identification of the monitoring location (e.g., unique monitoring location or heat exchange system ID number), the measured total strippable hydrocarbon concentration, the date the leak was first identified, and, if applicable, the date the source of the leak was identified;

(iv) For leaks that were repaired during the reporting period (including delayed repairs), identification of the monitoring location associated with the repaired leak, the total strippable hydrocarbon concentration measured during re-monitoring to verify repair, and the re-monitoring date (*i.e.*, the effective date of repair); and

(v) For each delayed repair, identification of the monitoring location associated with the leak for which repair is delayed, the date when the delay of repair began, the date the repair is expected to be completed (if the leak is not repaired during the reporting period), the total strippable hydrocarbon concentration and date of each monitoring event conducted on the delayed repair during the reporting period, and an estimate of the potential strippable hydrocarbon emissions over the reporting period associated with the delayed repair.

(10) For pressure relief devices subject to the requirements §63.648(j), Periodic Reports must include the information specified in paragraphs (g)(10)(i) through (iii) of this section.

(i) For pressure relief devices in organic HAP gas or vapor service, pursuant to §63.648(j)(1), report any instrument reading of 500 ppm or greater.

(ii) For pressure relief devices in organic HAP gas or vapor service subject to §63.648(j)(2), report confirmation that any monitoring required to be done during the reporting period to show compliance was conducted.

(iii) For pressure relief devices in organic HAP service subject to §63.648(j)(3), report each pressure release to the atmosphere, including duration of the pressure release and estimate of the mass quantity of each organic HAP released, and the results of any root cause analysis and corrective action analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(11) For flares subject to §63.670, Periodic Reports must include the information specified in paragraphs (g)(11)(i) through (iv) of this section.

(i) Records as specified in paragraph (i)(9)(i) of this section for each 15-minute block during which there was at least one minute when regulated material is routed to a flare and no pilot flame is present.

(ii) Visible emission records as specified in paragraph (i)(9)(ii)(C) of this section for each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes.

(iii) The 15-minute block periods for which the applicable operating limits specified in §63.670(d) through (f) are not met. Indicate the date and time for the period, the net heating value operating parameter(s) determined following the methods in §63.670(k) through (n) as applicable.

(iv) For flaring events meeting the criteria in §63.670(o)(3):

(A) The start and stop time and date of the flaring event.

(B) The length of time for which emissions were visible from the flare during the event.

(C) The periods of time that the flare tip velocity exceeds the maximum flare tip velocity determined using the methods in §63.670(d)(2) and the maximum 15-minute block average flare tip velocity recorded during the event.

(D) Results of the root cause and corrective actions analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(12) For delayed coking units, the Periodic Report must include the information specified in paragraphs (g)(12)(i) through (iv) of this section.

(i) For existing source delayed coking units, any 60-cycle average exceeding the applicable limit in §63.657(a)(1).

(ii) For new source delayed coking units, any direct venting event exceeding the applicable limit in §63.657(a)(2).

(iii) The total number of double quenching events performed during the reporting period.

(iv) For each double quenching draining event when the drain water temperature exceeded 210 °F, report the drum, date, time, the coke drum vessel pressure or temperature, as applicable, when pre-vent draining was initiated, and the maximum drain water temperature during the pre-vent draining period.

(13) For maintenance vents subject to the requirements in §63.643(c), Periodic Reports must include the information specified in paragraphs (g)(13)(i) through (iv) of this section for any release exceeding the applicable limits in §63.643(c)(1). For the purposes of this reporting requirement, owners or operators complying with §63.643(c)(1)(iv) must report each venting event for which the lower explosive limit is 20 percent or greater.

(i) Identification of the maintenance vent and the equipment served by the maintenance vent.

(ii) The date and time the maintenance vent was opened to the atmosphere.

(iii) The lower explosive limit, vessel pressure, or mass of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in §63.643(c)(1)(ii) was used and active purging was initiated while the lower explosive limit was 10 percent or greater, also include the lower explosive limit of the vapors at the time active purging was initiated.

(iv) An estimate of the mass of organic HAP released during the entire atmospheric venting event.

(14) Any changes in the information provided in a previous Notification of Compliance Status report.

(h) Other reports shall be submitted as specified in subpart A of this part and as follows:

(1) [Reserved]

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) In order to afford the Administrator the opportunity to have an observer present, the owner or operator shall notify the Administrator of the refilling of each Group 1 storage vessel that has been emptied and degassed.

(A) Except as provided in paragraphs (h)(2)(i) (B) and (C) of this section, the owner or operator shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP's to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

(B) Except as provided in paragraph (h)(2)(i)(C) of this section, if the internal inspection required by §63.120(a)(2), (a)(3), or (b)(10) of subpart G or §63.1063(d)(1) of subpart WW is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of this section for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of this section, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of this section for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by §63.120(b)(1) or (2) of subpart G or §63.1062(d)(3) of subpart WW. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in §63.652(h).

(4) The owner or operator who requests approval to monitor a different parameter than those listed in §63.644 for miscellaneous process vents or who is required by §63.653(a)(8) to establish a site-specific monitoring parameter for a point in an emissions average shall submit the information specified in paragraphs (h)(4)(i) through (h)(4)(iii) of this section. For new or reconstructed sources, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A and for existing sources, and the information shall be submitted no later than 18 months prior to the compliance date. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) A description of the parameter(s) to be monitored to determine whether excess emissions occur and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that they will establish a range for the monitored parameter as part of the Notification of Compliance Status report required in paragraphs (e) and (f) of this section.

(iii) The frequency and content of monitoring, recording, and reporting if: monitoring and recording are not continuous; or if periods of excess emissions, as defined in paragraph (g)(6) of this section, will not be identified in Periodic Reports required under paragraphs (e) and (g) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(5) An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in paragraph (i) of this section.

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in paragraphs (h)(5)(iii) through (h)(5)(iv) of this section, as applicable.

(ii) The provisions in §63.8(f)(5)(i) of subpart A of this part shall govern the review and approval of requests.

(iii) An owner or operator may use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The system shall be designed to:

(1) Measure the operating parameter value at least once every hour.

(2) Record at least 24 values each day during periods of operation.

(3) Record the date and time when monitors are turned off or on.

(4) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(5) Compute daily average values of the monitored operating parameter based on recorded data.

(B) You must maintain a record of the description of the monitoring system and data compression recording system including the criteria used to determine which monitored values

are recorded and retained, the method for calculating daily averages, and a demonstrations that they system meets all criteria of paragraph (h)(5)(iii)(A) of this section.

(iv) An owner or operator may request approval to use other alternative monitoring systems according to the procedures specified in §63.8(f) of subpart A of this part.

(6) The owner or operator shall submit the information specified in paragraphs (h)(6)(i) through (h)(6)(iii) of this section, as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(7) The owner or operator of a heat exchange system at an existing source must notify the Administrator at least 30 calendar days prior to changing from one of the monitoring options specified in §63.654(c)(4) to the other.

(8) For fenceline monitoring systems subject to §63.658, within 45 calendar days after the end of each reporting period, each owner or operator shall submit the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The owner or operator need not transmit these data prior to obtaining 12 months of data.

(i) Individual sample results for each monitor for each sampling period during the quarterly reporting period. For the first reporting period and for any period in which a passive monitor is added or moved, the owner or operator shall report the coordinates of all of the passive monitor locations. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. Coordinates shall be in decimal degrees with at least five decimal places.

(ii) The biweekly annual average concentration difference (Δc) values for benzene for the quarterly reporting period.

(iii) Notation for each biweekly value that indicates whether background correction was used, all measurements in the sampling period were below detection, or whether an outlier was removed from the sampling period data set.

(9) On and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, the owner or operator shall submit the results according to the procedures in paragraphs (h)(9)(i) and (ii) of this section.

(i) Within 60 days after the date of completing each performance test as required by this subpart, the owner or operator shall submit the results of the performance tests following the procedure specified in either paragraph (h)(9)(i)(A) or (B) of this section.

(A) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (<http://www.epa.gov/ttn/chief/ert/index.html>) at the time of the test, the owner or operator must submit the results of the performance test to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance test information being submitted is confidential business information (CBI), the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage 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 (h)(9)(i)(A).

(B) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, the owner or operator must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(ii) Within 60 days after the date of completing each CEMS performance evaluation as required by this subpart, the owner or operator must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(9)(ii)(A) or (B) of this section.

(A) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance evaluation information being submitted is CBI, the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage 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 (h)(9)(ii)(A).

(B) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(i) *Recordkeeping.* Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in paragraphs (i)(1) through (12) of this section. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, flash drive, floppy disk, magnetic tape, or microfiche.

(1) Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G except as specified in paragraphs (i)(1)(i) through (iv) of this section. Each owner or operator subject to the storage vessel provisions in §63.660 shall keep records as specified in paragraphs (i)(1)(v) and (vi) of this section.

(i) Records related to gaskets, slotted membranes, and sleeve seals are not required for storage vessels within existing sources.

(ii) All references to §63.122 in §63.123 of subpart G shall be replaced with §63.655(e).

(iii) All references to §63.150 in §63.123 of subpart G of this part shall be replaced with §63.652.

(iv) If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(v) Each owner or operator of a Group 1 storage vessel subject to the provisions in §63.660 shall keep records as specified in §63.1065 or §63.998, as applicable.

(vi) Each owner or operator of a Group 2 storage vessel shall keep the records specified in §63.1065(a) of subpart WW. If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained.

(2) Each owner or operator required to report the results of performance tests under paragraphs (f) and (g)(7) of this section shall retain a record of all reported results as well as a complete test report, as described in paragraph (f)(2)(ii) of this section for each emission point tested.

(3) Each owner or operator required to continuously monitor operating parameters under §63.644 for miscellaneous process vents or under §§63.652 and 63.653 for emission points in an emissions average shall keep the records specified in paragraphs (i)(3)(i) through (i)(3)(v) of this section unless an alternative recordkeeping system has been requested and approved under paragraph (h) of this section.

(i) The monitoring system shall measure data values at least once every hour.

(ii) The owner or operator shall record either:

(A) Each measured data value; or

(B) Block average values for 1 hour 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.

(iii) Daily average values of each continuously monitored parameter shall be calculated for each operating day and retained for 5 years except as specified in paragraph (i)(3)(iv) of this section.

(A) The daily average shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per day if operation is not continuous.

(B) The operating day shall be the period defined in the Notification of Compliance Status report. It may be from midnight to midnight or another daily period.

(iv) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status report, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that day. For these days, the records required in paragraph (i)(3)(ii) of this section shall also be retained for 5 years.

(v) Monitoring data recorded during periods of monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(4) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), the owner or operator shall keep a record of the information specified in either paragraph (i)(4)(i) or (ii) of this section, as applicable.

(i) The owner or operator shall maintain records of periods when flow was detected in the bypass line, including the date and time and the duration of the flow in the bypass line. For each flow

event, the owner or operator shall maintain records sufficient to determine whether or not the detected flow included flow of a Group 1 miscellaneous process vent stream requiring control. For periods when the Group 1 miscellaneous process vent stream requiring control is diverted from the control device and released either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), the owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting emissions of organic HAP that bypassed the control device using process knowledge and engineering estimates.

(ii) Where a seal mechanism is used to comply with §63.644(c)(2), hourly records of flow are not required. In such cases, the owner or operator shall record the date that the monthly visual inspection of the seals or closure mechanisms is completed. The owner or operator shall also record the occurrence of all periods when the seal or closure mechanism is broken, the bypass line valve position has changed or the key for a lock-and-key type lock has been checked out. The owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP from the Group 1 miscellaneous process vent stream requiring control that bypassed the control device or records sufficient to demonstrate that there was no flow of a Group 1 miscellaneous process vent stream requiring control during the period.

(5) The owner or operator of a heat exchange system subject to this subpart shall comply with the recordkeeping requirements in paragraphs (i)(5)(i) through (v) of this section and retain these records for 5 years.

(6) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

(7) Each owner or operator subject to the delayed coking unit decoking operations provisions in §63.657 must maintain records specified in paragraphs (i)(7)(i) through (iii) of this section.

(i) The average pressure or temperature, as applicable, for the 5-minute period prior to venting to the atmosphere, draining, or deheading the coke drum for each cooling cycle for each coke drum.

(ii) If complying with the 60-cycle rolling average, each 60-cycle rolling average pressure or temperature, as applicable, considering all coke drum venting events in the existing affected source.

(iii) For double-quench cooling cycles:

(A) The date, time and duration of each pre-vent draining event.

(B) The pressure or temperature of the coke drum vessel, as applicable, for the 15 minute period prior to the pre-vent draining.

(C) The drain water temperature at 1-minute intervals from the start of pre-vent draining to the complete closure of the drain valve.

(8) For fenceline monitoring systems subject to §63.658, each owner or operator shall keep the records specified in paragraphs (i)(8)(i) through (x) of this section on an ongoing basis.

(i) Coordinates of all passive monitors, including replicate samplers and field blanks, and if applicable, the meteorological station. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. The coordinates shall be in decimal degrees with at least five decimal places.

(ii) The start and stop times and dates for each sample, as well as the tube identifying information.

(iii) Sampling period average temperature and barometric pressure measurements.

(iv) For each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part, the sampler location of and the concentration of the outlier and the evidence used to conclude that the result is an outlier.

(v) For samples that will be adjusted for a background, the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies.

(vi) Individual sample results, the calculated Δc for benzene for each sampling period and the two samples used to determine it, whether background correction was used, and the annual average Δc calculated after each sampling period.

(vii) Method detection limit for each sample, including co-located samples and blanks.

(viii) Documentation of corrective action taken each time the action level was exceeded.

(ix) Other records as required by Methods 325A and 325B of appendix A of this part.

(x) If a near-field source correction is used as provided in §63.658(i), records of hourly meteorological data, including temperature, barometric pressure, wind speed and wind direction, calculated daily unit vector wind direction and daily sigma theta, and other records specified in the site-specific monitoring plan.

(9) For each flare subject to §63.670, each owner or operator shall keep the records specified in paragraphs (i)(9)(i) through (xii) of this section up-to-date and readily accessible, as applicable.

(i) Retain records of the output of the monitoring device used to detect the presence of a pilot flame as required in §63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when regulated material is routed to a flare for a minimum of 5 years.

(ii) Retain records of daily visible emissions observations or video surveillance images required in §63.670(h) as specified in the paragraphs (i)(9)(ii)(A) through (C), as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 at 40 CFR part 60, appendix A-7, the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. If the owner or operator performs visible emissions observations more than one time during a day, the record must also identify the date and time of day each visible emissions observation was performed.

(B) If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamps.

(C) For each 2 hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours, the record must include the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible.

(iii) The 15-minute block average cumulative flows for flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under §63.670(i), along with the date and time interval for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years.

(iv) The flare vent gas compositions specified to be monitored under §63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHVvg analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years.

(v) Each 15-minute block average operating parameter calculated following the methods specified in §63.670(k) through (n), as applicable.

(vi) [Reserved]

(vii) All periods during which operating values are outside of the applicable operating limits specified in §63.670(d) through (f) when regulated material is being routed to the flare.

(viii) All periods during which the owner or operator does not perform flare monitoring according to the procedures in §63.670(g) through (j).

(ix) Records of periods when there is flow of vent gas to the flare, but when there is no flow of regulated material to the flare, including the start and stop time and dates of periods of no regulated material flow.

(x) Records when the flow of vent gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.

(xi) Records of the root cause analysis and corrective action analysis conducted as required in §63.670(o)(3), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §63.670(o)(5)(i).

(xii) For any corrective action analysis for which implementation of corrective actions are required in §63.670(o)(5), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(10) [Reserved]

(11) For each pressure relief device subject to the pressure release management work practice standards in §63.648(j)(3), the owner or operator shall keep the records specified in paragraphs (i)(11)(i) through (iii) of this section.

(i) Records of the prevention measures implemented as required in §63.648(j)(3)(ii), if applicable.

(ii) Records of the number of releases during each calendar year and the number of those releases for which the root cause was determined to be a force majeure event. Keep these records for the current calendar year and the past five calendar years.

(iii) For each release to the atmosphere, the owner or operator shall keep the records specified in paragraphs (i)(11)(iii)(A) through (D) of this section.

(A) The start and end time and date of each pressure release to the atmosphere.

(B) Records of any data, assumptions, and calculations used to estimate of the mass quantity of each organic HAP released during the event.

(C) Records of the root cause analysis and corrective action analysis conducted as required in §63.648(j)(3)(iii), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §63.648(j)(7)(i).

(D) For any corrective action analysis for which implementation of corrective actions are required in §63.648(j)(7), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(12) For each maintenance vent opening subject to the requirements in §63.643(c), the owner or operator shall keep the applicable records specified in (i)(12)(i) through (v) of this section.

(i) The owner or operator shall maintain standard site procedures used to deinventory equipment for safety purposes (*e.g.*, hot work or vessel entry procedures) to document the procedures used to meet the requirements in §63.643(c). The current copy of the procedures shall be retained and available on-site at all times. Previous versions of the standard site procedures, if applicable, shall be retained for five years.

(ii) If complying with the requirements of §63.643(c)(1)(i) and the lower explosive limit at the time of the vessel opening exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(iii) If complying with the requirements of §63.643(c)(1)(ii) and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(iv) If complying with the requirements of §63.643(c)(1)(iii), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere for each applicable maintenance vent opening.

(v) If complying with the requirements of §63.643(c)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting the lack of a pure hydrogen supply, the date of maintenance vent opening, and the lower explosive limit of the vapors in the equipment at the time of discharge to the atmosphere for each applicable maintenance vent opening.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 44141, Aug. 18, 1998. Redesignated and amended at 74 FR 55686, 55687, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 78 FR 37148, June 20, 2013; 80 FR 75246, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.656 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.640, 63.642(g) through (l), 63.643, 63.646 through 63.652, 63.654, 63.657 through 63.660, and 63.670. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37351, June 23, 2003. Redesignated and amended at 74 FR 55686, 55688, Oct. 28, 2009; 80 FR 75253, Dec. 1, 2015]

§63.657 Delayed coking unit decoking operation standards.

(a) Except as provided in paragraphs (e) and (f) of this section, each owner or operator of a delayed coking unit shall depressure each coke drum to a closed blowdown system until the coke drum vessel pressure or temperature measured at the top of the coke drum or in the overhead line of the coke drum as near as practical to the coke drum meets the applicable limits specified in paragraph (a)(1) or (2) of this section prior to venting to the atmosphere, draining or deheading the coke drum at the end of the cooling cycle.

(1) For delayed coking units at an existing affected source, meet either:

- (i) An average vessel pressure of 2 psig determined on a rolling 60-event average; or
 - (ii) An average vessel temperature of 220 degrees Fahrenheit determined on a rolling 60-event average.
- (2) For delayed coking units at a new affected source, meet either:
- (i) A vessel pressure of 2.0 psig for each decoking event; or
 - (ii) A vessel temperature of 218 degrees Fahrenheit for each decoking event.
- (b) Each owner or operator of a delayed coking unit complying with the pressure limits in paragraph (a)(1)(i) or (a)(2)(i) of this section shall install, operate, calibrate, and maintain a monitoring system, as specified in paragraphs (b)(1) through (5) of this section, to determine the coke drum vessel pressure.
- (1) The pressure monitoring system must be in a representative location (at the top of the coke drum or in the overhead line as near as practical to the coke drum) that minimizes or eliminates pulsating pressure, vibration, and, to the extent practical, internal and external corrosion.
 - (2) The pressure monitoring system must be capable of measuring a pressure of 2.0 psig within ± 0.5 psig.
 - (3) The pressure monitoring system must be verified annually or at the frequency recommended by the instrument manufacturer. The pressure monitoring system must be verified following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale.
 - (4) All components of the pressure monitoring system must be visually inspected for integrity, oxidation and galvanic corrosion every 3 months, unless the system has a redundant pressure sensor.
 - (5) The output of the pressure monitoring system must be reviewed daily to ensure that the pressure readings fluctuate as expected between operating and cooling/decoking cycles to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired prior to the next operating cycle.
- (c) Each owner or operator of a delayed coking unit complying with the temperature limits in paragraph (a)(1)(ii) or (a)(2)(ii) of this section shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the coke drum vessel temperature (at the top of the coke drum or in the overhead line as near as practical to the coke drum) according to the requirements specified in table 13 of this subpart.
- (d) The owner or operator of a delayed coking unit shall determine the coke drum vessel pressure or temperature, as applicable, on a 5-minute rolling average basis while the coke drum is vented to the closed blowdown system and shall use the last complete 5-minute rolling average pressure

or temperature just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading to demonstrate compliance with the requirements in paragraph (a) of this section. Pressure or temperature readings after initiating steps to isolate the coke drum from the closed blowdown system just prior to atmospheric venting, draining, or deheading the coke drum shall not be used in determining the average coke drum vessel pressure or temperature for the purpose of compliance with the requirements in paragraph (a) of this section.

(e) The owner or operator of a delayed coking unit using the “water overflow” method of coke cooling must hardpipe the overflow water or otherwise prevent exposure of the overflow water to the atmosphere when transferring the overflow water to the overflow water storage tank whenever the coke drum vessel temperature exceeds 220 degrees Fahrenheit. The overflow water storage tank may be an open or fixed-roof tank provided that a submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank. The owner or operator of a delayed coking unit using the “water overflow” method of coke cooling shall determine the coke drum vessel temperature as specified in paragraphs (c) and (d) of this section regardless of the compliance method used to demonstrate compliance with the requirements in paragraph (a) of this section.

(f) The owner or operator of a delayed coking unit may partially drain a coke drum prior to achieving the applicable limits in paragraph (a) of this section in order to double-quench a coke drum that did not cool adequately using the normal cooling process steps provided that the owner or operator meets the conditions in paragraphs (f)(1) and (2) of this section.

(1) The owner or operator shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the drain water temperature at the bottom of the coke drum or in the drain line as near as practical to the coke drum according to the requirements specified in table 13 of this subpart.

(2) The owner or operator must maintain the drain water temperature below 210 degrees Fahrenheit during the partial drain associated with the double-quench event.

[80 FR 75253, Dec. 1, 2015]

§63.658 Fenceline monitoring provisions.

(a) The owner or operator shall conduct sampling along the facility property boundary and analyze the samples in accordance with Methods 325A and 325B of appendix A of this part and paragraphs (b) through (k) of this section.

(b) The target analyte is benzene.

(c) The owner or operator shall determine passive monitor locations in accordance with Section 8.2 of Method 325A of appendix A of this part.

(1) As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors, means a wastewater treatment unit,

process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine vessel loading operations, one passive monitor should be sited on the shoreline adjacent to the dock.

(2) The owner or operator may collect one or more background samples if the owner or operator believes that an offsite upwind source or an onsite source excluded under §63.640(g) may influence the sampler measurements. If the owner or operator elects to collect one or more background samples, the owner or operator must develop and submit a site-specific monitoring plan for approval according to the requirements in paragraph (i) of this section. Upon approval of the site-specific monitoring plan, the background sampler(s) should be operated co-currently with the routine samplers.

(3) The owner or operator shall collect at least one co-located duplicate sample for every 10 field samples per sampling period and at least two field blanks per sampling period, as described in Section 9.3 in Method 325A of appendix A of this part. The co-located duplicates may be collected at any one of the perimeter sampling locations.

(4) The owner or operator shall follow the procedure in Section 9.6 of Method 325B of appendix A of this part to determine the detection limit of benzene for each sampler used to collect samples, background samples (if the owner or operator elects to do so), co-located samples and blanks.

(d) The owner or operator shall collect and record meteorological data according to the applicable requirements in paragraphs (d)(1) through (3) of this section.

(1) If a near-field source correction is used as provided in paragraph (i)(1) of this section or if an alternative test method is used that provides time-resolved measurements, the owner or operator shall:

(i) Use an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part.

(ii) Collect and record hourly average meteorological data, including temperature, barometric pressure, wind speed and wind direction and calculate daily unit vector wind direction and daily sigma theta.

(2) For cases other than those specified in paragraph (d)(1) of this section, the owner or operator shall collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the refinery.

(3) If an on-site meteorological station is used, the owner or operator shall follow the calibration and standardization procedures for meteorological measurements in EPA-454/B-08-002 (incorporated by reference—see §63.14).

(e) The owner or operator shall use a sampling period and sampling frequency as specified in paragraphs (e)(1) through (3) of this section.

(1) *Sampling period.* A 14-day sampling period shall be used, unless a shorter sampling period is determined to be necessary under paragraph (g) or (i) of this section. A sampling period is defined as the period during which sampling tube is deployed at a specific sampling location with the diffusive sampling end cap in-place and does not include the time required to analyze the sample. For the purpose of this subpart, a 14-day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days, but the routine sampling period shall be 14 calendar days.

(2) *Base sampling frequency.* Except as provided in paragraph (e)(3) of this section, the frequency of sample collection shall be once each contiguous 14-day sampling period, such that the beginning of the next 14-day sampling period begins immediately upon the completion of the previous 14-day sampling period.

(3) *Alternative sampling frequency for burden reduction.* When an individual monitor consistently achieves results at or below $0.9 \mu\text{g}/\text{m}^3$, the owner or operator may elect to use the applicable minimum sampling frequency specified in paragraphs (e)(3)(i) through (v) of this section for that monitoring site. When calculating Δc for the monitoring period when using this alternative for burden reduction, zero shall be substituted for the sample result for the monitoring site for any period where a sample is not taken.

(i) If every sample at a monitoring site is at or below $0.9 \mu\text{g}/\text{m}^3$ for 2 years (52 consecutive samples), every other sampling period can be skipped for that monitoring site, *i.e.*, sampling will occur approximately once per month.

(ii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(i) of this section is at or below $0.9 \mu\text{g}/\text{m}^3$ for 2 years (*i.e.*, 26 consecutive “monthly” samples), five 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.*, sampling will occur approximately once per quarter.

(iii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(ii) of this section is at or below $0.9 \mu\text{g}/\text{m}^3$ for 2 years (*i.e.*, 8 consecutive quarterly samples), twelve 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.*, sampling will occur twice a year.

(iv) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(iii) of this section is at or below $0.9 \mu\text{g}/\text{m}^3$ for an 2 years (*i.e.*, 4 consecutive semi-annual samples), only one sample per year is required for that monitoring site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

(v) If at any time a sample for a monitoring site that is monitored at the frequency specified in paragraphs (e)(3)(i) through (iv) of this section returns a result that is above $0.9 \mu\text{g}/\text{m}^3$, the sampling site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for one quarter (six 14-day sampling periods). If every sample

collected during this quarter is at or below $0.9 \mu\text{g}/\text{m}^3$, the owner or operator may revert back to the reduced monitoring schedule applicable for that monitoring site prior to the sample reading exceeding $0.9 \mu\text{g}/\text{m}^3$. If any sample collected during this quarter is above $0.9 \mu\text{g}/\text{m}^3$, that monitoring site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for a minimum of two years. The burden reduction requirements can be used again for that monitoring site once the requirements of paragraph (e)(3)(i) of this section are met again, *i.e.*, after 52 contiguous 14-day samples with no results above $0.9 \mu\text{g}/\text{m}^3$.

(f) Within 45 days of completion of each sampling period, the owner or operator shall determine whether the results are above or below the action level as follows:

(1) The owner or operator shall determine the facility impact on the benzene concentration (Δc) for each 14-day sampling period according to either paragraph (f)(1)(i) or (ii) of this section, as applicable.

(i) Except when near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine the highest and lowest sample results for benzene concentrations from the sample pool and calculate Δc as the difference in these concentrations. The owner or operator shall adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for benzene:

(A) If the lowest detected value of benzene is below detection, the owner or operator shall use zero as the lowest sample result when calculating Δc .

(B) If all sample results are below the method detection limit, the owner or operator shall use the method detection limit as the highest sample result.

(ii) When near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine Δc using the calculation protocols outlined in the approved site-specific monitoring plan and in paragraph (i) of this section.

(2) The owner or operator shall calculate the annual average Δc based on the average of the 26 most recent 14-day sampling periods. The owner or operator shall update this annual average value after receiving the results of each subsequent 14-day sampling period.

(3) The action level for benzene is 9 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) on an annual average basis. If the annual average Δc value for benzene is less than or equal to $9 \mu\text{g}/\text{m}^3$, the concentration is below the action level. If the annual average Δc value for benzene is greater than $9 \mu\text{g}/\text{m}^3$, the concentration is above the action level, and the owner or operator shall conduct a root cause analysis and corrective action in accordance with paragraph (g) of this section.

(g) Within 5 days of determining that the action level has been exceeded for any annual average Δc and no longer than 50 days after completion of the sampling period, the owner or operator shall initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action, such as those described in paragraphs (g)(1) through (4) of this section. The root cause analysis and initial corrective action analysis shall be completed and

initial corrective actions taken no later than 45 days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to:

(1) Leak inspection using Method 21 of part 60, appendix A-7 of this chapter and repairing any leaks found.

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

(3) Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions.

(4) Employing progressively more frequent sampling, analysis and meteorology (*e.g.*, using shorter sampling periods for Methods 325A and 325B of appendix A of this part, or using active sampling techniques).

(h) If, upon completion of the corrective action analysis and corrective actions such as those described in paragraph (g) of this section, the Δc value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than $9 \mu\text{g}/\text{m}^3$ or if all corrective action measures identified require more than 45 days to implement, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures. The owner or operator shall submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the 14-day sampling period following the completion of the initial corrective action is greater than $9 \mu\text{g}/\text{m}^3$ or, if no initial corrective actions were identified, no later than 60 days following the completion of the corrective action analysis required in paragraph (g) of this section.

(i) An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under §63.640(g) according to the requirements in paragraphs (i)(1) through (4) of this section.

(1) The owner or operator shall prepare and submit a site-specific monitoring plan and receive approval of the site-specific monitoring plan prior to using the near-field source alternative calculation for determining Δc provided in paragraph (i)(2) of this section. The site-specific monitoring plan shall include, at a minimum, the elements specified in paragraphs (i)(1)(i) through (v) of this section. The procedures in Section 12 of Method 325A of appendix A of this part are not required, but may be used, if applicable, when determining near-field source contributions.

(i) Identification of the near-field source or sources. For onsite sources, documentation that the onsite source is excluded under §63.640(g) and identification of the specific provision in §63.640(g) that applies to the source.

(ii) Location of the additional monitoring stations that shall be used to determine the uniform background concentration and the near-field source concentration contribution.

(iii) Identification of the fenceline monitoring locations impacted by the near-field source. If more than one near-field source is present, identify the near-field source or sources that are expected to contribute to the concentration at that monitoring location.

(iv) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(v) If more frequent monitoring or a monitoring station other than a passive diffusive tube monitoring station is proposed, provide a detailed description of the measurement methods, measurement frequency, and recording frequency for determining the uniform background or near-field source concentration contribution.

(2) When an approved site-specific monitoring plan is used, the owner or operator shall determine Δc_i for comparison with the 9 $\mu\text{g}/\text{m}^3$ action level using the requirements specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δc_i using the following equation.

$$\Delta c_i = MFC_i - NFS_i - UB$$

Where:

Δc_i = The fenceline concentration, corrected for background, at measurement location i, micrograms per cubic meter ($\mu\text{g}/\text{m}^3$).

MFC_i = The measured fenceline concentration at measurement location i, $\mu\text{g}/\text{m}^3$.

NFS_i = The near-field source contributing concentration at measurement location i determined using the additional measurements and calculation procedures included in the site-specific monitoring plan, $\mu\text{g}/\text{m}^3$. For monitoring locations that are not included in the site-specific monitoring plan as impacted by a near-field source, use $NFS_i = 0 \mu\text{g}/\text{m}^3$.

UB = The uniform background concentration determined using the additional measurements included in the site-specific monitoring plan, $\mu\text{g}/\text{m}^3$. If no additional measurements are specified in the site-specific monitoring plan for determining the uniform background concentration, use $UB = 0 \mu\text{g}/\text{m}^3$.

(ii) When one or more samples for the sampling period are below the method detection limit for benzene, adhere to the following procedures:

(A) If the benzene concentration at the monitoring location used for the uniform background concentration is below the method detection limit, the owner or operator shall use zero for UB for that monitoring period.

(B) If the benzene concentration at the monitoring location(s) used to determine the near-field source contributing concentration is below the method detection limit, the owner or operator shall use zero for the monitoring location concentration when calculating NFS_i for that monitoring period.

(C) If a fenceline monitoring location sample result is below the method detection limit, the owner or operator shall use the method detection limit as the sample result.

(iii) Determine Δc for the monitoring period as the maximum value of Δc_i from all of the fenceline monitoring locations for that monitoring period.

(3) The site-specific monitoring plan shall be submitted and approved as described in paragraphs (i)(3)(i) through (iv) of this section.

(i) The site-specific monitoring plan must be submitted to the Administrator for approval.

(ii) The site-specific monitoring plan shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to refineryrtr@epa.gov.

(iii) The Administrator shall approve or disapprove the plan in 90 days. The plan shall be considered approved if the Administrator either approves the plan in writing, or fails to disapprove the plan in writing. The 90-day period shall begin when the Administrator receives the plan.

(iv) If the Administrator finds any deficiencies in the site-specific monitoring plan and disapproves the plan in writing, the owner or operator may revise and resubmit the site-specific monitoring plan following the requirements in paragraphs (i)(3)(i) and (ii) of this section. The 90-day period starts over with the resubmission of the revised monitoring plan.

(4) The approval by the Administrator of a site-specific monitoring plan will be based on the completeness, accuracy and reasonableness of the request for a site-specific monitoring plan. Factors that the Administrator will consider in reviewing the request for a site-specific monitoring plan include, but are not limited to, those described in paragraphs (i)(4)(i) through (v) of this section.

(i) The identification of the near-field source or sources. For onsite sources, the documentation provided that the onsite source is excluded under §63.640(g).

(ii) The monitoring location selected to determine the uniform background concentration or an indication that no uniform background concentration monitor will be used.

(iii) The location(s) selected for additional monitoring to determine the near-field source concentration contribution.

(iv) The identification of the fenceline monitoring locations impacted by the near-field source or sources.

(v) The appropriateness of the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(vi) If more frequent monitoring is proposed, the adequacy of the description of the measurement and recording frequency proposed and the adequacy of the rationale for using the alternative monitoring frequency.

(j) The owner or operator shall comply with the applicable recordkeeping and reporting requirements in §63.655(h) and (i).

(k) As outlined in §63.7(f), the owner or operator may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraphs (k)(1) through (7) of this section.

(1) The alternative method may be used in lieu of all or a partial number of passive samplers required in Method 325A of appendix A of this part.

(2) The alternative method must be validated according to Method 301 in appendix A of this part or contain performance based procedures and indicators to ensure self-validation.

(3) The method detection limit must nominally be at least an order of magnitude below the action level, *i.e.*, 0.9 µg/m³ benzene. The alternate test method must describe the procedures used to provide field verification of the detection limit.

(4) The spatial coverage must be equal to or better than the spatial coverage provided in Method 325A of appendix A of this part.

(i) For path average concentration open-path instruments, the physical path length of the measurement shall be no more than a passive sample footprint (the spacing that would be provided by the sorbent traps when following Method 325A). For example, if Method 325A requires spacing monitors A and B 610 meters (2000 feet) apart, then the physical path length limit for the measurement at that portion of the fenceline shall be no more than 610 meters (2000 feet).

(ii) For range resolved open-path instrument or approach, the instrument or approach must be able to resolve an average concentration over each passive sampler footprint within the path length of the instrument.

(iii) The extra samplers required in Sections 8.2.1.3 of Method 325A may be omitted when they fall within the path length of an open-path instrument.

(5) At a minimum, non-integrating alternative test methods must provide a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(6) For alternative test methods capable of real time measurements (less than a 5 minute sampling and analysis cycle), the alternative test method may allow for elimination of data points corresponding to outside emission sources for purpose of calculation of the high point for the two week average. The alternative test method approach must have wind speed, direction and stability class of the same time resolution and within the footprint of the instrument.

(7) For purposes of averaging data points to determine the Δc for the 14-day average high sample result, all results measured under the method detection limit must use the method detection limit. For purposes of averaging data points for the 14-day average low sample result, all results measured under the method detection limit must use zero.

[80 FR 75254, Dec. 1, 2015, as amended at 81 FR 45241, July 13, 2016]

§63.660 Storage vessel provisions.

On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in §63.640(h), the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW or SS of this part according to the requirements in paragraphs (a) through (i) of this section.

(a) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A, WW, or SS of this part. The definitions of “Group 1 storage vessel” (paragraph (2)) and “Storage vessel” in §63.641 shall apply in lieu of the definition of “Storage vessel” in §63.1061.

(1) An owner or operator may use good engineering judgment or test results to determine the stored liquid weight percent total organic HAP for purposes of group determination. Data, assumptions, and procedures used in the determination shall be documented.

(2) When an owner or operator and the Administrator do not agree on whether the annual average weight percent organic HAP in the stored liquid is above or below 4 percent for a storage vessel at an existing source or above or below 2 percent for a storage vessel at a new source, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street NW., 6th Floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005-4070, (202) 682-8000,

<http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.naesb.org>).

(b) A floating roof storage vessel complying with the requirements of subpart WW of this part may comply with the control option specified in paragraph (b)(1) of this section and, if equipped with a ladder having at least one slotted leg, shall comply with one of the control options as described in paragraph (b)(2) of this section.

(1) In addition to the options presented in §§63.1063(a)(2)(viii)(A) and (B) and 63.1064, a floating roof storage vessel may comply with §63.1063(a)(2)(vii) using a flexible enclosure device and either a gasketed or welded cap on the top of the guidepole.

(2) Each opening through a floating roof for a ladder having at least one slotted leg shall be equipped with one of the configurations specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) A pole float in the slotted leg and pole wipers for both legs. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(ii) A ladder sleeve and pole wipers for both legs of the ladder.

(iii) A flexible enclosure device and either a gasketed or welded cap on the top of the slotted leg.

(c) For the purposes of this subpart, references shall apply as specified in paragraphs (c)(1) through (6) of this section.

(1) All references to “the proposal date for a referencing subpart” and “the proposal date of the referencing subpart” in subpart WW of this part mean June 30, 2014.

(2) All references to “promulgation of the referencing subpart” and “the promulgation date of the referencing subpart” in subpart WW of this part mean February 1, 2016.

(3) All references to “promulgation date of standards for an affected source or affected facility under a referencing subpart” in subpart SS of this part mean February 1, 2016.

(4) All references to “the proposal date of the relevant standard established pursuant to CAA section 112(f)” in subpart SS of this part mean June 30, 2014.

(5) All references to “the proposal date of a relevant standard established pursuant to CAA section 112(d)” in subpart SS of this part mean July 14, 1994.

(6) All references to the “required control efficiency” in subpart SS of this part mean reduction of organic HAP emissions by 95 percent or to an outlet concentration of 20 ppmv.

(d) For an uncontrolled fixed roof storage vessel that commenced construction on or before June 30, 2014, and that meets the definition of “Group 1 storage vessel”, paragraph (2), in §63.641 but

not the definition of “Group 1 storage vessel”, paragraph (1), in §63.641, the requirements of §63.982 and/or §63.1062 do not apply until the next time the storage vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first.

(e) Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart.

(f) References in §63.1066(a) to initial startup notification requirements do not apply.

(g) References to the Notification of Compliance Status in §63.999(b) mean the Notification of Compliance Status required by §63.655(f).

(h) References to the Periodic Reports in §§63.1066(b) and 63.999(c) mean the Periodic Report required by §63.655(g).

(i) Owners or operators electing to comply with the requirements in subpart SS of this part for a Group 1 storage vessel must comply with the requirements in paragraphs (i)(1) through (3) of this section.

(1) If a flare is used as a control device, the flare shall meet the requirements of §63.670 instead of the flare requirements in §63.987.

(2) If a closed vent system contains a bypass line, the owner or operator shall comply with the provisions of either §63.983(a)(3)(i) or (ii) for each closed vent system that contains bypass lines that could divert a vent stream either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part. Except as provided in paragraphs (i)(2)(i) and (ii) of this section, use of the bypass at any time to divert a Group 1 storage vessel to either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part is an emissions standards violation. Equipment such as low leg drains and equipment subject to §63.648 are not subject to this paragraph (i)(2).

(i) If planned routine maintenance of the control device cannot be performed during periods that storage vessel emissions are vented to the control device or when the storage vessel is taken out of service for inspections or other planned maintenance reasons, the owner or operator may bypass the control device.

(ii) Periods for which storage vessel control device may be bypassed for planned routine maintenance of the control device shall not exceed 240 hours per calendar year.

(3) If storage vessel emissions are routed to a fuel gas system or process, the fuel gas system or process shall be operating at all times when regulated emissions are routed to it. The exception in §63.984(a)(1) does not apply.

[80 FR 75257, Dec. 1, 2015]

§63.670 Requirements for flare control devices.

On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to this subpart shall meet the applicable requirements for flares as specified in paragraphs (a) through (q) of this section and the applicable requirements in §63.671. The owner or operator may elect to comply with the requirements of paragraph (r) of this section in lieu of the requirements in paragraphs (d) through (f) of this section, as applicable.

(a) [Reserved]

(b) *Pilot flame presence.* The owner or operator shall operate each flare with a pilot flame present at all times when regulated material is routed to the flare. Each 15-minute block during which there is at least one minute where no pilot flame is present when regulated material is routed to the flare is a deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. The owner or operator shall monitor for the presence of a pilot flame as specified in paragraph (g) of this section.

(c) *Visible emissions.* The owner or operator shall specify the smokeless design capacity of each flare and operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare. The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.

(d) *Flare tip velocity.* For each flare, the owner or operator shall comply with either paragraph (d)(1) or (2) of this section, provided the appropriate monitoring systems are in-place, whenever regulated material is routed to the flare for at least 15-minutes and the flare vent gas flow rate is less than the smokeless design capacity of the flare.

(1) Except as provided in paragraph (d)(2) of this section, the actual flare tip velocity (V_{tip}) must be less than 60 feet per second. The owner or operator shall monitor V_{tip} using the procedures specified in paragraphs (i) and (k) of this section.

(2) V_{tip} must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (V_{max}) as calculated according to the following equation. The owner or operator shall monitor V_{tip} using the procedures specified in paragraphs (i) and (k) of this section and monitor gas composition and determine NHV_{vg} using the procedures specified in paragraphs (j) and (l) of this section.

$$\log_{10}(V_{max}) = \frac{NHV_{vg} + 1,212}{850}$$

Where:

V_{max} = Maximum allowed flare tip velocity, ft/sec.

NHV_{vg} = Net heating value of flare vent gas, as determined by paragraph (l)(4) of this section, Btu/scf.

1,212 = Constant.

850 = Constant.

(e) *Combustion zone operating limits.* For each flare, the owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{cz} as specified in paragraph (m) of this section.

(f) *Dilution operating limits for flares with perimeter assist air.* For each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value dilution parameter (NHV_{dil}) at or above 22 British thermal units per square foot (Btu/ft²) determined on a 15-minute block period basis when regulated material is being routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{dil} as specified in paragraph (n) of this section.

(g) *Pilot flame monitoring.* The owner or operator shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

(h) *Visible emissions monitoring.* The owner or operator shall monitor visible emissions while regulated materials are vented to the flare. An initial visible emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A-7. Subsequent visible emissions observations must be conducted using either the methods in paragraph (h)(1) of this section or, alternatively, the methods in paragraph (h)(2) of this section. The owner or operator must record and report any instances where visible emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in §63.655(g)(11)(ii).

(1) At least once per day, conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If at any time the owner or operator sees visible emissions, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, appendix A-7 must be extended to 2 hours or until 5-minutes of visible emissions are observed.

(2) Use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The owner or operator must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time.

(i) *Flare vent gas, steam assist and air assist flow rate monitoring.* The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the

flare as well as any supplemental natural gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the flare vent gas provided that the flow rates of all gas streams that contribute to the flare vent gas are determined. If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare. If pre-mix assist air and perimeter assist are both used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of pre-mix assist air and perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

(1) The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in standard conditions (*i.e.*, a temperature of 20 °C (68 °F) and a pressure of 1 atmosphere).

(2) Mass flow monitors may be used for determining volumetric flow rate of flare vent gas provided the molecular weight of the flare vent gas is determined using compositional analysis as specified in paragraph (j) of this section so that the mass flow rate can be converted to volumetric flow at standard conditions using the following equation.

$$Q_{vol} = \frac{Q_{mass} \times 385.3}{MW_t}$$

[View or download PDF](#)

Where:

Q_{vol} = Volumetric flow rate, standard cubic feet per second.

Q_{mass} = Mass flow rate, pounds per second.

385.3 = Conversion factor, standard cubic feet per pound-mole.

MW_t = Molecular weight of the gas at the flow monitoring location, pounds per pound-mole.

(3) Mass flow monitors may be used for determining volumetric flow rate of assist air or assist steam. Use equation in paragraph (i)(2) of this section to convert mass flow rates to volumetric flow rates. Use a molecular weight of 18 pounds per pound-mole for assist steam and use a molecular weight of 29 pounds per pound-mole for assist air.

(4) Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring systems provided the molecular weight of the gas is known. For assist steam, use a molecular weight of 18 pounds per pound-mole. For assist air, use a molecular weight of 29 pounds per pound-mole. For flare vent gas, molecular weight must be determined using compositional analysis as specified in paragraph (j) of this section.

(j) *Flare vent gas composition monitoring.* The owner or operator shall determine the concentration of individual components in the flare vent gas using either the methods provided in paragraph (j)(1) or (2) of this section, to assess compliance with the operating limits in paragraph (e) of this section and, if applicable, paragraphs (d) and (f) of this section. Alternatively, the owner or operator may elect to directly monitor the net heating value of the flare vent gas following the methods provided in paragraphs (j)(3) of this section and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in paragraphs (j)(4) of this section. The owner or operator may elect to use different monitoring methods for different gaseous streams that make up the flare vent gas using different methods provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined.

(1) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (*i.e.*, at least once every 15-minutes), calculating, and recording the individual component concentrations present in the flare vent gas.

(2) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours while there is flow of regulated material to the flare. Subsequent compositional analysis of the samples must be performed according to Method 18 of 40 CFR part 60, appendix A-6, ASTM D6420-99 (Reapproved 2010), ASTM D1945-03 (Reapproved 2010), ASTM D1945-14 or ASTM UOP539-12 (all incorporated by reference—see §63.14).

(3) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at standard conditions.

(4) If the owner or operator uses a continuous net heating value monitor according to paragraph (j)(3) of this section, the owner or operator may, at their discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas.

(5) Direct compositional or net heating value monitoring is not required for purchased (“pipeline quality”) natural gas streams. The net heating value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any purchased natural gas stream can be assumed to be 920 Btu/scf.

(6) Direct compositional or net heating value monitoring is not required for gas streams that have been demonstrated to have consistent composition (or a fixed minimum net heating value) according to the methods in paragraphs (j)(6)(i) through (v) of this section.

(i) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(A) A description of the flare gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the flare gas stream/system and the affected flare(s) to be considered;

(B) A statement that there are no crossover or entry points to be introduced into the flare gas stream/system (this should be shown in the piping diagrams) prior to the point where the flow rate of the gas streams is measured;

(C) An explanation of the conditions that ensure that the flare gas net heating value is consistent and, if flare gas net heating value is expected to vary (*e.g.*, due to product loading of different material), the conditions expected to produce the flare gas with the lowest net heating value;

(D) The supporting test results from sampling the requested flare gas stream/system for the net heating value. Sampling data must include, at minimum, 2 weeks of daily measurement values (14 grab samples) for frequently operated flare gas streams/systems; for infrequently operated flare gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. If the flare gas stream composition can vary, samples must be taken during those conditions expected to result in lowest net heating value identified in paragraph (j)(6)(i)(C) of this section. The owner or operator shall determine net heating value for the gas stream using either gas composition analysis or net heating value monitor (with optional hydrogen concentration analyzer) according to the method provided in paragraph (l) of this section; and

(E) A description of how the 2 weeks (or seven samples for infrequently operated flare gas streams/systems) of monitoring results compares to the typical range of net heating values expected for the flare gas stream/system going to the affected flare (*e.g.*, “the samples are representative of typical operating conditions of the flare gas stream going to the loading rack flare” or “the samples are representative of conditions expected to yield the lowest net heating value of the flare gas stream going to the loading rack flare”).

(F) The net heating value to be used for all flows of the flare vent gas from the flare gas stream/system covered in the application. A single net heating value must be assigned to the flare vent gas either by selecting the lowest net heating value measured in the sampling program or by determining the 95th percent confidence interval on the mean value of all samples collected using the t-distribution statistic (which is 1.943 for 7 grab samples or 1.771 for 14 grab samples).

(ii) The effective date of the exemption is the date of submission of the information required in paragraph (j)(6)(i) of this section.

(iii) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (*e.g.*, the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (j)(6)(iii)(A), (B), or (C) of this section.

(A) If the operation change results in a flare vent gas net heating value that is still within the range of net heating values included in the original application, the owner or operator shall

determine the net heating value on a grab sample and record the results as proof that the net heating value assigned to the vent gas stream in the original application is still appropriate.

(B) If the operation change results in a flare vent gas net heating value that is lower than the net heating value assigned to the vent gas stream in the original application, the owner or operator may submit new information following the procedures of paragraph (j)(6)(i) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(C) If the operation change results in a flare vent gas net heating value has greater variability in the flare gas stream/system such the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin monitoring the composition or net heat content of the flare vent gas stream using the methods in this section (*i.e.*, grab samples every 8 hours until such time a continuous monitor, if elected, is installed).

(k) *Calculation methods for cumulative flow rates and determining compliance with V_{tip} operating limits.* The owner or operator shall determine V_{tip} on a 15-minute block average basis according to the following requirements.

(1) The owner or operator shall use design and engineering principles to determine the unobstructed cross sectional area of the flare tip. The unobstructed cross sectional area of the flare tip is the total tip area that vent gas can pass through. This area does not include any stability tabs, stability rings, and upper steam or air tubes because flare vent gas does not exit through them.

(2) The owner or operator shall determine the cumulative volumetric flow of flare vent gas for each 15-minute block average period using the data from the continuous flow monitoring system required in paragraph (i) of this section according to the following requirements, as applicable. If desired, the cumulative flow rate for a 15-minute block period only needs to include flow during those periods when regulated material is sent to the flare, but owners or operators may elect to calculate the cumulative flow rates across the entire 15-minute block period for any 15-minute block period where there is regulated material flow to the flare.

(i) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block average flow volumes.

(ii) If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under paragraph (i)(4) of this section, the owner or operator shall, at a minimum, determine the 15-minute block average temperature and pressure from the monitoring system and use those values to perform the engineering calculations to determine the cumulative flow over the 15-minute block average period. Alternatively, the owner or operator may divide the 15-minute block average period into equal duration subperiods(*e.g.*, three 5-minute periods) and determine the average temperature and pressure for each subperiod, perform engineering calculations to determine the flow for each subperiod, then add the volumetric flows for the

subperiods to determine the cumulative volumetric flow of vent gas for the 15-minute block average period.

(3) The 15-minute block average V_{tip} shall be calculated using the following equation.

$$V_{tip} = \frac{Q_{cum}}{Area \times 900}$$

[View or download PDF](#)

Where:

V_{tip} = Flare tip velocity, feet per second.

Q_{cum} = Cumulative volumetric flow over 15-minute block average period, actual cubic feet.

Area = Unobstructed area of the flare tip, square feet.

900 = Conversion factor, seconds per 15-minute block average.

(4) If the owner or operator chooses to comply with paragraph (d)(2) of this section, the owner or operator shall also determine the net heating value of the flare vent gas following the requirements in paragraphs (j) and (l) of this section and calculate V_{max} using the equation in paragraph (d)(2) of this section in order to compare V_{tip} to V_{max} on a 15-minute block average basis.

(l) *Calculation methods for determining flare vent gas net heating value.* The owner or operator shall determine the net heating value of the flare vent gas (NHV_{vg}) based on the composition monitoring data on a 15-minute block average basis according to the following requirements.

(1) If compositional analysis data are collected as provided in paragraph (j)(1) or (2) of this section, the owner or operator shall determine NHV_{vg} of a specific sample by using the following equation.

$$NHV_{vg} = \sum_{i=1}^n x_i NHV_i$$

[View or download PDF](#)

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.

i = Individual component in flare vent gas.

n = Number of components in flare vent gas.

x_i = Concentration of component i in flare vent gas, volume fraction.

NHV_i = Net heating value of component i according to table 12 of this subpart, Btu/scf. If the component is not specified in table 12 of this subpart, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of vent gas is 20 °C.

(2) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section but a hydrogen concentration monitor is not used, the owner or operator shall use the direct output of the monitoring system(s) (in Btu/scf) to determine the NHV_{vg} for the sample.

(3) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section and hydrogen concentration monitoring data are collected as provided in paragraph (j)(4) of this section, the owner or operator shall use the following equation to determine NHV_{vg} for each sample measured via the net heating value monitoring system.

$$NHV_{vg} = NHV_{measured} + 938x_{H_2}$$

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.

$NHV_{measured}$ = Net heating value of flare vent gas stream as measured by the continuous net heating value monitoring system, Btu/scf.

x_{H_2} = Concentration of hydrogen in flare vent gas at the time the sample was input into the net heating value monitoring system, volume fraction.

938 = Net correction for the measured heating value of hydrogen (1,212 – 274), Btu/scf.

(4) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block averages.

(5) When a continuous monitoring system is used as provided in paragraph (j)(1) or (3) of this section and, if applicable, paragraph (j)(4) of this section, the owner or operator may elect to determine the 15-minute block average NHV_{vg} using either the calculation methods in paragraph (l)(5)(i) of this section or the calculation methods in paragraph (l)(5)(ii) of this section. The owner or operator may choose to comply using the calculation methods in paragraph (l)(5)(i) of this section for some flares at the petroleum refinery and comply using the calculation methods (l)(5)(ii) of this section for other flares. However, for each flare, the owner or operator must elect one calculation method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the owner or operator intends to change the calculation method that applies to a flare, the owner or operator must notify the Administrator 30 days in advance of such a change.

(i) *Feed-forward calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) Use the results from the first sample collected during an event, (for periodic flare vent gas flow events) for the first 15-minute block associated with that event.

(B) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the second 15-minute block associated with that event.

(C) For all other cases, use the results that are available from the most recent sample prior to the 15-minute block period for that 15-minute block period for all flare vent gas streams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:45 a.m. to 1:00 a.m.

(ii) *Direct calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the first 15-minute block associated with that event.

(B) For all other cases, use the arithmetic average of all NHV_{vg} measurement data results that become available during a 15-minute block to calculate the 15-minute block average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:30 a.m. to 12:45 a.m.

(6) When grab samples are used to determine flare vent gas composition:

(i) Use the analytical results from the first grab sample collected for an event for all 15-minute periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected.

(ii) Use the results from subsequent grab sampling events for all 15 minute periods starting with the 15-minute block in which the sample was collected and ending with the 15-minute block prior to the 15-minute block in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

(7) If the owner or operator monitors separate gas streams that combine to comprise the total flare vent gas flow, the 15-minute block average net heating value shall be determined separately for each measurement location according to the methods in paragraphs (1)(1) through (6) of this

section and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

(m) *Calculation methods for determining combustion zone net heating value.* The owner or operator shall determine the net heating value of the combustion zone gas (NHV_{cz}) as specified in paragraph (m)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (m)(2) of this section, determine the 15-minute block average NHV_{cz} based on the 15-minute block average vent gas and assist gas flow rates using the following equation. For periods when there is no assist steam flow or premix assist air flow, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{(Q_{vg} + Q_s + Q_{a,premix})}$$

[View or download PDF](#)

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (1)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{cz} using the following equation.

$$NHV_{cz} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG}}{(Q_{vg} + Q_s + Q_{a,premix})}$$

[View or download PDF](#)

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.*, $Q_{NG1}=Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(n) *Calculation methods for determining the net heating value dilution parameter.* The owner or operator shall determine the net heating value dilution parameter (NHV_{dil}) as specified in paragraph (n)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (n)(2) of this section, determine the 15-minute block average NHV_{dil} based on the 15-minute block average vent gas and perimeter assist air flow rates using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter})}$$

[View or download PDF](#)

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft².

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi} .$$

[View or download PDF](#)

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (1)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{dil} using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{[(Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG}] \times Diam}{(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter})}$$

[View or download PDF](#)

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft².

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.*, $Q_{NG1} = Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi} .$$

[View or download PDF](#)

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(o) *Emergency flaring provisions.* The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in paragraphs (o)(1) through (8) of this section.

(1) Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The flare management plan must include the information described in paragraphs (o)(1)(i) through (vii) of this section.

(i) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(ii) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized or prevented during periods of startup, shutdown, or emergency releases. The flare minimization assessment must (at a minimum) consider the items in paragraphs (o)(1)(ii)(A) through (C) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(A) Modification in startup and shutdown procedures to reduce the quantity of process gas discharge to the flare.

(B) Implementation of prevention measures listed for pressure relief devices in §63.648(j)(5) for each pressure relief device that can discharge to the flare.

(C) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iii) A description of each affected flare containing the information in paragraphs (o)(1)(iii)(A) through (G) of this section.

(A) A general description of the flare, including whether it is a ground flare or elevated (including height), the type of assist system (*e.g.*, air, steam, pressure, non-assisted), whether the flare is used on a routine basis or if it is only used during periods of startup, shutdown or emergency release, and whether the flare is equipped with a flare gas recovery system.

(B) The smokeless capacity of the flare based on design conditions. Note: A single value must be provided for the smokeless capacity of the flare.

(C) The maximum vent gas flow rate (hydraulic load capacity).

(D) The maximum supplemental gas flow rate.

(E) For flares that receive assist steam, the minimum total steam rate and the maximum total steam rate.

(F) For flares that receive assist air, an indication of whether the fan/blower is single speed, multi-fixed speed (*e.g.*, high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated assist air flow rate at each fixed speed. For variable speeds, provide the design fan curve (*e.g.*, air flow rate as a function of power input).

(G) Simple process flow diagram showing the locations of the flare following components of the flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iv) Description and simple process flow diagram showing all gas lines (including flare waste gas, purge or sweep gas (as applicable), supplemental gas) that are associated with the flare. For purge, sweep, supplemental gas, identify the type of gas used. Designate which lines are exempt from composition or net heating value monitoring and why (*e.g.*, natural gas, gas streams that have been demonstrated to have consistent composition, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the flare.

(v) For each flow rate, gas composition, net heating value or hydrogen concentration monitor identified in paragraph (o)(1)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For each pressure relief device vented to the flare identified in paragraph (o)(1)(iv) of this section, provide a detailed description of each pressure release device, including type of relief device (rupture disc, valve type) diameter of the relief device opening, set pressure of the relief device and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator.

(vii) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(2) Each owner or operator required to develop and implement a written flare management plan as described in paragraph (o)(1) of this section must submit the plan to the Administrator as described in paragraphs (o)(2)(i) through (iii) of this section.

(i) The owner or operator must develop and implement the flare management plan no later than January 30, 2019 or at startup for a new flare that commenced construction on or after February 1, 2016.

(ii) The owner or operator must comply with the plan as submitted by the date specified in paragraph (o)(2)(i) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator alters the design smokeless capacity of the flare. The owner or operator must comply with the updated plan as submitted.

(iii) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryRTR@epa.gov*.

(3) The owner or operator of a flare subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either the criteria in paragraph (o)(3)(i) or (ii) of this section.

(i) The vent gas flow rate exceeds the smokeless capacity of the flare and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event.

(ii) The vent gas flow rate exceeds the smokeless capacity of the flare and the 15-minute block average flare tip velocity exceeds the maximum flare tip velocity determined using the methods in paragraph (d)(2) of this section.

(4) A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a flare flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (o)(4)(i) through (v) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event that meets both of the criteria in paragraphs (o)(3)(i) and (ii) of this section.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event regardless of the number of 15-minute block periods in which the flare tip velocity was exceeded or the number of 2 hour periods that contain more the 5 minutes of visible emissions.

(iii) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares that are operated in series (*i.e.*, cascaded flare systems) to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section.

(iv) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section, regardless of the configuration of the flares, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(v) Except as provided in paragraphs (o)(4)(iii) and (iv) of this section, if more than one flare has a flow event that meets the criteria in paragraph (o)(3)(i) or (ii) of this section during the same time period, an initial root cause analysis shall be conducted separately for each flare that has a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. If the initial root cause analysis indicates that the flow events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(5) Each owner or operator of a flare required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (o)(3) and (4) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (o)(5)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(6) The owner or operator shall determine the total number of events for which a root cause and corrective action analyses was required during the calendar year for each affected flare separately for events meeting the criteria in paragraph (o)(3)(i) of this section and those meeting the criteria in paragraph (o)(3)(ii) of this section. For the purpose of this requirement, a single root cause analysis conducted for an event that met both of the criteria in paragraphs (o)(3)(i) and (ii) of this section would be counted as an event under each of the separate criteria counts for that flare. Additionally, if a single root cause analysis was conducted for an event that caused multiple flares to meet the criteria in paragraph (o)(3)(i) or (ii) of this section, that event would count as an event for each of the flares for each criteria in paragraph (o)(3) of this section that was met during that event. The owner or operator shall also determine the total number of events for which a root cause and corrective action analyses was required and the analyses concluded that the root cause was a force majeure event, as defined in this subpart.

(7) The following events would be a violation of this emergency flaring work practice standard.

(i) Any flow event for which a root cause analysis was required and the root cause was determined to be operator error or poor maintenance.

(ii) Two visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iii) Two flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iv) Three visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(v) Three flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(p) *Flare monitoring records.* The owner or operator shall keep the records specified in §63.655(i)(9).

(q) *Reporting.* The owner or operator shall comply with the reporting requirements specified in §63.655(g)(11).

(r) *Alternative means of emissions limitation.* An owner or operator may request approval from the Administrator for site-specific operating limits that shall apply specifically to a selected flare. Site-specific operating limits include alternative threshold values for the parameters specified in paragraphs (d) through (f) of this section as well as threshold values for operating parameters other than those specified in paragraphs (d) through (f) of this section. The owner or operator must demonstrate that the flare achieves 96.5 percent combustion efficiency (or 98 percent destruction efficiency) using the site-specific operating limits based on a performance evaluation as described in paragraph (r)(1) of this section. The request shall include information as described in paragraph (r)(2) of this section. The request shall be submitted and followed as described in paragraph (r)(3) of this section.

(1) The owner or operator shall prepare and submit a site-specific test plan and receive approval of the site-specific performance evaluation plan prior to conducting any flare performance evaluation test runs intended for use in developing site-specific operating limits. The site-specific performance evaluation plan shall include, at a minimum, the elements specified in paragraphs (r)(1)(i) through (ix) of this section. Upon approval of the site-specific performance evaluation plan, the owner or operator shall conduct performance evaluation test runs for the flare following the procedures described in the site-specific performance evaluation plan.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) The operating conditions (vent gas compositions, vent gas flow rates and assist flow rates, if applicable) likely to be encountered by the flare during normal operations and the operating conditions for the test period.

(iii) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare combustion or destruction efficiency.

(iv) Site-specific operating parameters to be monitored continuously during the flare performance evaluation. These parameters may include but are not limited to vent gas flow rate, steam and/or air assist flow rates, and flare vent gas composition. If new operating parameters are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of the relevance of the proposed operating parameter(s) as an indicator of flare combustion performance and why the alternative operating parameter(s) can adequately ensure that the flare achieves the required combustion efficiency.

(v) A detailed description of the measurement methods, monitored pollutant(s), measurement locations, measurement frequency, and recording frequency proposed for both emission measurements and flare operating parameters.

(vi) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare operating parameters.

(vii) The minimum number and length of test runs and range of operating values to be evaluated during the performance evaluation. A sufficient number of test runs shall be conducted to identify the point at which the combustion/destruction efficiency of the flare deteriorates.

(viii) [Reserved]

(ix) Test schedule.

(2) The request for flare-specific operating limits shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the selected site-specific operating limit(s) adequately ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times. At a minimum, the request shall contain the information described in paragraphs (r)(2)(i) through (iv) of this section.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) Results of each performance evaluation test run conducted, including, at a minimum:

(A) The measured combustion/destruction efficiency.

(B) The measured or calculated operating parameters for each test run. If operating parameters are calculated, the raw data from which the parameters are calculated must be included in the test report.

(C) Measurement location descriptions for both emission measurements and flare operating parameters.

(D) Description of sampling and analysis procedures (including number and length of test runs) and any modifications to standard procedures. If there were deviations from the approved test plan, a detailed description of the deviations and rationale why the test results or calculation procedures used are appropriate.

(E) Operating conditions (*e.g.*, vent gas composition, assist rates, etc.) that occurred during the test.

(F) Quality assurance procedures.

(G) Records of calibrations.

(H) Raw data sheets for field sampling.

(I) Raw data sheets for field and laboratory analyses.

(J) Documentation of calculations.

(iii) The selected flare-specific operating limit values based on the performance evaluation test results, including the averaging time for the operating limit(s), and rationale why the selected values and averaging times are sufficiently stringent to ensure proper flare performance. If new operating parameters or averaging times are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of why the alternative operating parameter(s) or averaging time(s) adequately ensures the flare achieves the required combustion efficiency.

(iv) The means by which the owner or operator will document on-going, continuous compliance with the selected flare-specific operating limit(s), including the specific measurement location and frequencies, calculation procedures, and records to be maintained.

(3) The request shall be submitted as described in paragraphs (r)(3)(i) through (iv) of this section.

(i) The owner or operator may request approval from the Administrator at any time upon completion of a performance evaluation conducted following the methods in an approved site-

specific performance evaluation plan for an operating limit(s) that shall apply specifically to that flare.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must continue to comply with the applicable standards for flares in this subpart until the requirements in §63.6(g)(1) are met and a notice is published in the FEDERAL REGISTER allowing use of such an alternative means of emission limitation.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryrtr@epa.gov*.

(iv) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval within 45 days of receipt of the notice of deficiencies. The owner or operator must comply with the revised request as submitted until it is approved.

(4) The approval process for a request for a flare-specific operating limit(s) is described in paragraphs (r)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a flare-specific operating limit(s) request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, those described in paragraphs (r)(4)(i)(A) through (C) of this section.

(A) The description of the flare design and operating characteristics.

(B) If a new operating parameter(s) other than those specified in paragraphs (d) through (f) of this section is proposed, the explanation of how the proposed operating parameter(s) serves a good indicator(s) of flare combustion performance.

(C) The results of the flare performance evaluation test runs and the establishment of operating limits that ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times.

(D) The completeness of the flare performance evaluation test report.

(ii) If the request is approved by the Administrator, a flare-specific operating limit(s) will be established at the level(s) demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[80 FR 75258, Dec. 1, 2015, as amended at 81 FR 45241, July 13, 2016]

§63.671 Requirements for flare monitoring systems.

(a) *Operation of CPMS.* For each CPMS installed to comply with applicable provisions in §63.670, the owner or operator shall install, operate, calibrate, and maintain the CPMS as specified in paragraphs (a)(1) through (8) of this section.

(1) Except for CPMS installed for pilot flame monitoring, all monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

(2) The owner or operator shall ensure the readout (that portion of the CPMS that provides a visual display or record) or other indication of the monitored operating parameter from any CPMS required for compliance is readily accessible onsite for operational control or inspection by the operator of the source.

(3) All CPMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period.

(4) 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, calibration checks and required zero and span adjustments), the owner or operator shall operate all CPMS and collect data continuously at all times when regulated emissions are routed to the flare.

(5) The owner or operator shall operate, maintain, and calibrate each CPMS according to the CPMS monitoring plan specified in paragraph (b) of this section.

(6) For each CPMS except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraph (c) of this section.

(7) The owner or operator shall reduce data from a CPMS as specified in paragraph (d) of this section.

(8) The CPMS must be capable of measuring the appropriate parameter over the range of values expected for that measurement location. The data recording system associated with each CPMS must have a resolution that is equal to or better than the required system accuracy.

(b) *CPMS monitoring plan.* The owner or operator shall develop and implement a CPMS quality control program documented in a CPMS monitoring plan that covers each flare subject to the provisions in §63.670 and each CPMS installed to comply with applicable provisions in §63.670. The owner or operator shall have the CPMS monitoring plan readily available on-site at all times and shall submit a copy of the CPMS monitoring plan to the Administrator upon request by the Administrator. The CPMS monitoring plan must contain the information listed in paragraphs (b)(1) through (5) of this section.

- (1) Identification of the specific flare being monitored and the flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted).
- (2) Identification of the parameter to be monitored by the CPMS and the expected parameter range, including worst case and normal operation.
- (3) Description of the monitoring equipment, including the information specified in paragraphs (b)(3)(i) through (vii) of this section.
 - (i) Manufacturer and model number for all monitoring equipment components installed to comply with applicable provisions in §63.670.
 - (ii) Performance specifications, as provided by the manufacturer, and any differences expected for this installation and operation.
 - (iii) The location of the CPMS sampling probe or other interface and a justification of how the location meets the requirements of paragraph (a)(1) of this section.
 - (iv) Placement of the CPMS readout, or other indication of parameter values, indicating how the location meets the requirements of paragraph (a)(2) of this section.
 - (v) Span of the CPMS. The span of the CPMS sensor and analyzer must encompass the full range of all expected values.
 - (vi) How data outside of the span of the CPMS will be handled and the corrective action that will be taken to reduce and eliminate such occurrences in the future.
 - (vii) Identification of the parameter detected by the parametric signal analyzer and the algorithm used to convert these values into the operating parameter monitored to demonstrate compliance, if the parameter detected is different from the operating parameter monitored.
- (4) Description of the data collection and reduction systems, including the information specified in paragraphs (b)(4)(i) through (iii) of this section.
 - (i) A copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard and to calculate the applicable averages.
 - (ii) Identification of whether the algorithm excludes data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable) and high-level adjustments.
 - (iii) If the data acquisition algorithm does not exclude data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if

applicable) and high-level adjustments, a description of the procedure for excluding this data when the averages calculated as specified in paragraph (e) of this section are determined.

(5) Routine quality control and assurance procedures, including descriptions of the procedures listed in paragraphs (b)(5)(i) through (vi) of this section and a schedule for conducting these procedures. The routine procedures must provide an assessment of CPMS performance.

(i) Initial and subsequent calibration of the CPMS and acceptance criteria.

(ii) Determination and adjustment of the calibration drift of the CPMS.

(iii) Daily checks for indications that the system is responding. If the CPMS system includes an internal system check, the owner or operator may use the results to verify the system is responding, as long as the system provides an alarm to the owner or operator or the owner or operator checks the internal system results daily for proper operation and the results are recorded.

(iv) Preventive maintenance of the CPMS, including spare parts inventory.

(v) Data recording, calculations and reporting.

(vi) Program of corrective action for a CPMS that is not operating properly.

(c) *Out-of-control periods.* For each CPMS installed to comply with applicable provisions in §63.670 except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraphs (c)(1) and (2) of this section.

(1) A CPMS is out-of-control if the zero (low-level), mid-level (if applicable) or high-level calibration drift exceeds two times the accuracy requirement of table 13 of this subpart.

(2) When the CPMS is out of control, the owner or operator shall take the necessary corrective action and repeat all necessary tests that indicate the system is out of control. The owner or operator shall take corrective action and conduct retesting until the performance requirements are below the applicable limits. The beginning of the out-of-control period is the hour a performance check (*e.g.*, calibration drift) that indicates an exceedance of the performance requirements established in this section is conducted. The end of the out-of-control period is the hour following the completion of corrective action and successful demonstration that the system is within the allowable limits. The owner or operator shall not use data recorded during periods the CPMS is out of control in data averages and calculations, used to report emissions or operating levels, as specified in paragraph (d)(3) of this section.

(d) *CPMS data reduction.* The owner or operator shall reduce data from a CPMS installed to comply with applicable provisions in §63.670 as specified in paragraphs (d)(1) through (3) of this section.

(1) The owner or operator may round the data to the same number of significant digits used in that operating limit.

(2) Periods of non-operation of the process unit (or portion thereof) resulting in cessation of the emissions to which the monitoring applies must not be included in the 15-minute block averages.

(3) Periods when the CPMS is out of control must not be included in the 15-minute block averages.

(e) *Additional requirements for gas chromatographs.* For monitors used to determine compositional analysis for net heating value per §63.670(j)(1), the gas chromatograph must also meet the requirements of paragraphs (e)(1) through (3) of this section.

(1) The quality assurance requirements are in table 13 of this subpart.

(2) The calibration gases must meet one of the following options:

(i) The owner or operator must use a calibration gas or multiple gases that include all of compounds listed in paragraphs (e)(2)(i)(A) through (K) of this section that may be reasonably expected to exist in the flare gas stream and optionally include any of the compounds listed in paragraphs (e)(2)(i)(L) through (O) of this section. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.

(A) Hydrogen.

(B) Methane.

(C) Ethane.

(D) Ethylene.

(E) Propane.

(F) Propylene.

(G) n-Butane.

(H) iso-Butane.

(I) Butene (general). It is not necessary to separately speciate butene isomers, but the net heating value of trans-butene must be used for co-eluting butene isomers.

(J) 1,3-Butadiene. It is not necessary to separately speciate butadiene isomers, but you must use the response factor and net heating value of 1,3-butadiene for co-eluting butadiene isomers.

(K) n-Pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.

(L) Acetylene (optional).

(M) Carbon monoxide (optional).

(N) Propadiene (optional).

(O) Hydrogen sulfide (optional).

(ii) The owner or operator must use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.

(3) If the owner or operator chooses to use a surrogate calibration gas under paragraph (e)(2)(ii) of this section, the owner or operator must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) Use the response factor for the nearest normal hydrocarbon (*i.e.*, n-alkane) in the calibration mixture to quantify unknown components detected in the analysis.

(ii) Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

[80 FR 75266, Dec. 1, 2015]

§§63.672-63.679 [Reserved]

Appendix to Subpart CC of Part 63—Tables

Table 1—Hazardous Air Pollutants

Chemical name	CAS No. ^a
Benzene	71432
Biphenyl	92524
Butadiene (1,3)	106990
Carbon disulfide	75150
Carbonyl sulfide	463581
Cresol (mixed isomers ^b)	1319773
Cresol (m-)	108394
Cresol (o-)	95487

Cresol (p-)	106445
Cumene	98828
Dibromoethane (1,2) (ethylene dibromide)	106934
Dichloroethane (1,2)	107062
Diethanolamine	111422
Ethylbenzene	100414
Ethylene glycol	107211
Hexane	110543
Methanol	67561
Methyl isobutyl ketone (hexone)	108101
Methyl tert butyl ether	1634044
Naphthalene	91203
Phenol	108952
Toluene	108883
Trimethylpentane (2,2,4)	540841
Xylene (mixed isomers ^b)	1330207
xylene (m-)	108383
xylene (o-)	95476
xylene (p-)	106423

^aCAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

^bIsomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

Table 2—Leak Definitions for Pumps and Valves

Standard ^a	Phase	Leak definition (parts per million)
§63.163 (pumps)	I	10,000
	II	5,000
	III	2,000
§63.168 (valves)	I	10,000
	II	1,000
	III	1,000

^aSubpart H of this part.

Table 3—Equipment Leak Recordkeeping and Reporting Requirements for Sources Complying With §63.648 of Subpart CC by Compliance With Subpart H of this Part^a

Reference (section of subpart H of this part)	Description	Comment
63.181(a)	Recordkeeping system requirements	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(b)	Records required for process unit equipment	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(c)	Visual inspection documentation	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(d)	Leak detection record requirements	Except for §63.181(d)(8).
63.181(e)	Compliance requirements for pressure tests for batch product process equipment trains	This subsection does not apply to subpart CC.
63.181(f)	Compressor compliance test records.	
63.181(g)	Closed-vent systems and control device record requirements.	
63.181(h)	Process unit quality improvement program records.	
63.181(i)	Heavy liquid service determination record.	
63.181(j)	Equipment identification record.	
63.181(k)	Enclosed-vented process unit emission limitation record requirements.	
63.182(a)	Reports.	
63.182(b)	Initial notification report requirements.	Not required.
63.182(c)	Notification of compliance status report	Except in §63.182(c); change “within 90 days of the compliance dates” to “within 150 days of the compliance dates”; except in §§63.182 (c)(2) and (c)(4).
63.182(d)	Periodic report	Except for §§63.182 (d)(2)(vii), (d)(2)(viii),

		and (d)(3).
--	--	-------------

^aThis table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 4—Gasoline Distribution Emission Point Recordkeeping and Reporting Requirements^a

Reference (section of subpart R)	Description	Comment
63.428(b) or (k)	Records of test results for each gasoline cargo tank loaded at the facility	
63.428(c)	Continuous monitoring data recordkeeping requirements	
63.428(g)(1)	Semiannual report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.428(h)(1) through (h)(3)	Excess emissions report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.

^aThis table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 5—Marine Vessel Loading Operations Recordkeeping and Reporting Requirements^a

Reference (section of subpart Y)	Description	Comment
63.562(e)(2)	Operation and maintenance plan for control equipment and monitoring equipment	
63.565(a)	Performance test/site test plan	The information required under this paragraph is to be submitted with the Notification of Compliance Status report required under 40 CFR part 63, subpart CC.
63.565(b)	Performance test data requirements	
63.567(a)	General Provisions (subpart A) applicability	
63.567(c)	Request for extension of compliance	

63.567(d)	Flare recordkeeping requirements	
63.567(e)	Summary report and excess emissions and monitoring system performance report requirements	The information required under this paragraph is to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.567(f)	Vapor collection system engineering report	
63.567(g)	Vent system valve bypass recordkeeping requirements	
63.567(h)	Marine vessel vapor-tightness documentation	
63.567(i)	Documentation file maintenance	
63.567(j)	Emission estimation reporting and recordkeeping procedures	

^aThis table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 6—General Provisions Applicability to Subpart CC^a

Reference	Applies to subpart CC	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	Yes	
63.1(a)(5)	No	Reserved.
63.1(a)(6)	Yes	Except the correct mail drop (MD) number is C404-04.
63.1(a)(7)-63.1(a)(9)	No	Reserved.
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12)	Yes	
63.1(b)(1)	Yes	
63.1(b)(2)	No	Reserved.
63.1(b)(3)	No	
63.1(c)(1)	Yes	
63.1(c)(2)	No	Area sources are not subject to subpart CC.

63.1(c)(3)- 63.1(c)(4)	No	Reserved.
63.1(c)(5)	Yes	Except that sources are not required to submit notifications overridden by this table.
63.1(d)	No	Reserved.
63.1(e)	No	No CAA section 112(j) standard applies to the affected sources under subpart CC.
63.2	Yes	§63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC.
63.3	Yes	
63.4(a)(1)- 63.4(a)(2)	Yes	
63.4(a)(3)- 63.4(a)(5)	No	Reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)	Yes	
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	Except the cross-reference to §63.9(b) is changed to §63.9(b)(4) and (5). Subpart CC overrides §63.9 (b)(2).
63.5(b)(5)	No	Reserved.
63.5(b)(6)	Yes	
63.5(c)	No	Reserved.
63.5(d)(1)(i)	Yes	Except that the application shall be submitted as soon as practicable before startup, but no later than 90 days after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC.
63.5(d)(1)(ii)	Yes	Except that for affected sources subject to this subpart, emission estimates specified in §63.5(d)(1)(ii)(H) are not required, and §63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
63.5(d)(1)(iii)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	

63.5(f)	Yes	Except that the cross-reference in §63.5(f)(2) to §63.9(b)(2) does not apply.
63.6(a)	Yes	
63.6(b)(1)- 63.6(b)(5)	No	Subpart CC specifies compliance dates and notifications for sources subject to subpart CC.
63.6(b)(6)	No	Reserved.
63.6(b)(7)	Yes	
63.6(c)(1)- 63.6(c)(2)	No	§63.640 of subpart CC specifies the compliance date.
63.6(c)(3)- 63.6(c)(4)	No	Reserved.
63.6(c)(5)	Yes	
63.6(d)	No	Reserved.
63.6(e)(1)(i) and (ii)	No	See §63.642(n) for general duty requirement.
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No	Reserved.
63.6(e)(3)(i)	No.	
63.6(e)(3)(ii)	No	Reserved.
63.6(e)(3)(iii)- 63.6(e)(3)(ix)	No.	
63.6(f)(1)	No.	
63.6(f)(2)	Yes	Except the phrase “as specified in §63.7(c)” in §63.6(f)(2)(iii)(D) does not apply because this subpart does not require a site-specific test plan.
63.6(f)(3)	Yes	Except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.642(n).
63.6(g)	Yes	
63.6(h)(1)	No.	
63.6(h)(2)	Yes	Except §63.6(h)(2)(ii), which is reserved.
63.6(h)(3)	No	Reserved.
63.6(h)(4)	No	Notification of visible emission test not required in subpart CC.
63.6(h)(5)	No	Visible emission requirements and timing is specified in §63.645(i) of subpart CC.
63.6(h)(6)	Yes	
63.6(h)(7)	No	Subpart CC does not require opacity standards.
63.6(h)(8)	Yes	
63.6(h)(9)	No	Subpart CC does not require opacity standards.
63.6(i)	Yes	Except for §63.6(i)(15), which is reserved.

63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after compliance date, as specified in §63.655(f) of subpart CC.
63.7(a)(3)	Yes	
63.7(a)(4)	Yes	
63.7(b)	Yes	Except this subpart requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.
63.7(c)	No	Subpart CC does not require a site-specific test plan.
63.7(d)	Yes	
63.7(e)(1)	No	See §63.642(d)(3).
63.7(e)(2)- 63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives without additional notification or approval.
63.7(g)	No	Performance test reporting specified in §63.655(f).
63.7(h)(1)	Yes	
63.7(h)(2)	Yes	
63.7(h)(3)	Yes	Yes, except site-specific test plans shall not be required, and where §63.7(g)(3) specifies submittal by the date the site-specific test plan is due, the date shall be 90 days prior to the Notification of Compliance Status report in §63.655(f).
63.7(h)(4)(i)	Yes	
63.7(h)(4)(ii)	No	Site-specific test plans are not required in subpart CC.
63.7(h)(4)(iii) and (iv)	Yes	
63.7(h)(5)	Yes	
63.8(a)(1) and (2)	Yes.	
63.8(a)(3)	No	Reserved.
63.8(a)(4)	Yes	Except that for a flare complying with §63.670, the cross-reference to §63.11 in this paragraph does not include §63.11(b).
63.8(b)	Yes	
63.8(c)(1)	Yes	Except §63.8(c)(1)(i) and (iii).
63.8(c)(1)(i)	No	See §63.642(n).
63.8(c)(1)(iii)	No.	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	Except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or

		recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately.
63.8(c)(4)	Yes	Except that for sources other than flares, this subpart specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is “once every hour” rather than “for each successive 15-minute period.”
63.8(c)(5)- 63.8(c)(8)	No	This subpart specifies continuous monitoring system requirements.
63.8(d)	No	This subpart specifies quality control procedures for continuous monitoring systems.
63.8(e)	Yes.	
63.8(f)(1)	Yes	
63.8(f)(2)	Yes	
63.8(f)(3)	Yes	
63.8(f)(4)(i)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(5)	Yes	
63.8(f)(6)	No	Subpart CC does not require continuous emission monitors.
63.8(g)	No	This subpart specifies data reduction procedures in §§63.655(i)(3) and 63.671(d).
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in §63.9(a)(4)(ii).
63.9(b)(1)	Yes	Except the notification of compliance status report specified in §63.655(f) of subpart CC may also serve as the initial compliance notification required in §63.9(b)(1)(iii).
63.9(b)(2)	No	A separate Initial Notification report is not required under subpart CC.
63.9(b)(3)	No	Reserved.
63.9(b)(4)	Yes	Except for subparagraphs §63.9(b)(4)(ii) through (iv), which are reserved.
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test and does not require a site-specific test plan.

63.9(f)	No	Subpart CC does not require advanced notification of visible emissions test.
63.9(g)	No	
63.9(h)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§63.655(i) of subpart CC specifies record retention requirements.
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	§63.655(i) specifies the records that must be kept.
63.10(b)(2)(iii)	No	
63.10(b)(2)(iv)	No.	
63.10(b)(2)(v)	No.	
63.10(b)(2)(vi)	Yes	
63.10(b)(2)(vii)	No	§63.655(i) specifies records to be kept for parameters measured with continuous monitors.
63.10(b)(2)(viii)	Yes	
63.10(b)(2)(ix)	Yes	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xi)	No	
63.10(b)(2)(xii)	Yes	
63.10(b)(2)(xiii)	No	
63.10(b)(2)(xiv)	Yes	
63.10(b)(3)	No	
63.10(c)(1)- 63.10(c)(6)	No	
63.10(c)(7) and 63.10(c)(8)	Yes	
63.10(c)(9)	No	Reserved.
63.10(c)(10)- 63.10(c)(11)	No	§63.655(i) specifies the records that must be kept.
63.10(c)(12)- 63.10(c)(15)	No.	
63.10(d)(1)	Yes	
63.10(d)(2)	No	Although §63.655(f) specifies performance test reporting, EPA may approve other timeframes for submittal of performance test data.

63.10(d)(3)	No	Results of visible emissions test are included in Compliance Status Report as specified in §63.655(f).
63.10(d)(4)	Yes	
63.10(d)(5)	No	§63.655(g) specifies the reporting requirements.
63.10(e)	No	
63.10(f)	Yes	
63.11	Yes	Except that flares complying with §63.670 are not subject to the requirements of §63.11(b).
63.12-63.16	Yes.	

^aWherever subpart A of this part specifies “postmark” dates, submittals may be sent by methods other than the U.S. Mail (*e.g.*, by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

Table 7—Fraction Measured (F_M), Fraction Emitted (F_E), and Fraction Removed (FR) for HAP Compounds in Wastewater Streams

Chemical name	CAS No. ^a	F_M	F_E	Fr
Benzene	71432	1.00	0.80	0.99
Biphenyl	92524	0.86	0.45	0.99
Butadiene (1,3)	106990	1.00	0.98	0.99
Carbon disulfide	75150	1.00	0.92	0.99
Cumene	98828	1.00	0.88	0.99
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00	0.64	0.99
Ethylbenzene	100414	1.00	0.83	0.99
Hexane	110543	1.00	1.00	0.99
Methanol	67561	0.85	0.17	0.31
Methyl isobutyl ketone (hexone)	108101	0.98	0.53	0.99
Methyl tert butyl ether	1634044	1.00	0.57	0.99
Naphthalene	91203	0.99	0.51	0.99
Trimethylpentane (2,2,4)	540841	1.00	1.00	0.99
xylene (m-)	108383	1.00	0.82	0.99
xylene (o-)	95476	1.00	0.79	0.99
xylene (p-)	106423	1.00	0.82	0.99

^aCAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

Table 8—Valve Monitoring Frequency for Phase III

Performance level	Valve monitoring frequency
Leaking valves^a (%)	
≥4	Monthly or QIP. ^b
<4	Quarterly.
<3	Semiannual.
<2	Annual.

^aPercent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

^bQIP = Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 9—Valve Monitoring Frequency for Alternative

Performance level	Valve monitoring frequency under §63.649 alternative
Leaking valves^a (%)	
≥5	Monthly or QIP. ^b
<5	Quarterly.
<4	Semiannual.
<3	Annual.

^aPercent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

^bQIP = Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 10—Miscellaneous Process Vents—Monitoring, Recordkeeping and Reporting Requirements for Complying With 98 Weight-Percent Reduction of Total Organic HAP Emissions or a Limit of 20 Parts Per Million by Volume

Control device	Parameters to be monitored^a	Recordkeeping and reporting requirements for monitored parameters
Thermal incinerator	Firebox temperature ^b (63.644(a)(1)(i))	1. Continuous records ^c .
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS ^d .
		3. Record the daily average firebox temperature for each operating day ^e .
		4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all

		operating days when insufficient monitoring data are collected ^f —PR ^g .
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii))	1. Continuous records ^c .
		2. Record and report the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test—NCS ^d .
		3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day ^e .
		4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR ^g .
		5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR ^g .
		6. Report all operating days when insufficient monitoring data are collected ^f .
Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is <i>not</i> introduced into the flame zone ^{hi}	Firebox temperature ^b (63.644(a)(4))	1. Continuous records ^c .
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS ^d .
		3. Record the daily average firebox temperature for each operating day ^e .
		4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected ^f —PR ^g .

Flare (if meeting the requirements of §§63.643 and 63.644)	Presence of a flame at the pilot light (63.644(a)(2))	1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour.
		2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS ^d .
		3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
		4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
Flare (if meeting the requirements of §§63.670 and 63.671)	The parameters specified in §63.670	1. Records as specified in §63.655(i)(9). 2. Report information as specified in §63.655(g)(11)—PR. ^g
All control devices	Presence of flow diverted to the atmosphere from the control device (§63.644(c)(1)) <i>or</i>	1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR. ^g
	Monthly inspections of sealed valves (§63.644(c)(2))	1. Records that monthly inspections were performed. 2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR. ^g

^aRegulatory citations are listed in parentheses.

^bMonitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

^c“Continuous records” is defined in §63.641.

^dNCS = Notification of Compliance Status Report described in §63.655.

^cThe daily average is the average of all recorded parameter values for the operating day. If all recorded values during an operating day are within the range established in the NCS or operating permit, a statement to this effect can be recorded instead of the daily average.

^fWhen a period of excess emission is caused by insufficient monitoring data, as described in §63.655(g)(6)(i)(C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

^gPR = Periodic Reports described in §63.655(g).

^hNo monitoring is required for boilers and process heaters with a design heat capacity ≥ 44 megawatts or for boilers and process heaters where all vent streams are introduced into the flame zone. No recordkeeping or reporting associated with monitoring is required for such boilers and process heaters.

ⁱProcess vents that are routed to refinery fuel gas systems are not regulated under this subpart provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are in compliance with §63.670. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

Table 11—Compliance Dates and Requirements

If the construction/reconstruction date is . . .	Then the owner or operator must comply with . . .	And the owner or operator must achieve compliance . . .	Except as provided in . . .
(1) After June 30, 2014	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); 63.649 through 63.651; and 63.654 through 63.656	Upon initial startup	§63.640(k), (l) and (m).
	(ii) Requirements for new sources in §§63.642(n), 63.643(c), 63.648(j)(3), (6) and (7); and 63.657 through 63.660	Upon initial startup or February 1, 2016, whichever is later	§63.640(k), (l) and (m).
(2) After September 4, 2007 but on or before June 30, 2014	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); and 63.649 through 63.651,	Upon initial startup	§63.640(k), (l) and (m).

	63.655 and 63.656		
	(ii) Requirements for new sources in §63.654	Upon initial startup or October 28, 2009, whichever is later	§63.640(k), (l) and (m).
	(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	Upon initial startup, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(v) Requirements for existing sources in §63.658	On or before January 30, 2018	§63.640(k), (l) and (m).
	(vi) Requirements for existing sources in §63.648 (j)(3), (6) and (7) and §63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(vii) Requirements in §63.642 (n)	Upon initial startup or February 1, 2016, whichever is later	
(3) After July 14, 1994 but on or before September 4, 2007	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); and 63.649 through 63.651, 63.655 and 63.656	Upon initial startup or August 18, 1995, whichever is later	§63.640(k), (l) and (m).
	(ii) Requirements for existing sources in §63.654	On or before October 29, 2012	§63.640(k), (l) and (m).
	(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	Upon initial startup, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(v) Requirements for	On or before January	§63.640(k), (l) and

	existing sources in §63.658	30, 2018	(m).
	(vi) Requirements for existing sources in §§63.648(j)(3), (6) and (7) and 63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(vii) Requirements in §63.642(n)	Upon initial startup or February 1, 2016, whichever is later	
(4) On or before July 14, 1994	(i) Requirements for existing sources in §§63.648(a) through (i) and (j)(1) and (2); and 63.649, 63.655 and 63.656	(A) On or before August 18, 1998	(1) §63.640(k), (l) and (m). (2) §63.6(c)(5) or unless an extension has been granted by the Administrator as provided in §63.6(i).
	(ii) Either the requirements for existing sources in §§63.643(a) and (b); 63.644, 63.645, 63.647, 63.650 and 63.651; and item (4)(v) of this table OR The requirements in §§63.652 and 63.653	(A) On or before August 18, 1998	(1) §63.640(k), (l) and (m). (2) §63.6(c)(5) or unless an extension has been granted by the Administrator as provided in §63.6(i).
	(iii) Requirements for existing sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	On or before August 18, 1998, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.654	On or before October 29, 2012	§63.640(k), (l) and (m).
	(v) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(vi) Requirements for existing sources in §63.658	On or before January 30, 2018	§63.640(k), (l) and (m).
	(vii) Requirements for existing sources in §§63.648(j)(3), (6) and (7) and 63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(viii) Requirements in	Upon initial startup or	

	§63.642 (n)	February 1, 2016, whichever is later	
--	-------------	---	--

Table 12—Individual Component Properties

Component	Molecular formula	MW_i (pounds per pound- mole)	CMN_i (mole per mole)	NHV_i (British thermal units per standard cubic foot)	LFL_i (volume %)
Acetylene	C ₂ H ₂	26.04	2	1,404	2.5
Benzene	C ₆ H ₆	78.11	6	3,591	1.3
1,2-Butadiene	C ₄ H ₆	54.09	4	2,794	2.0
1,3-Butadiene	C ₄ H ₆	54.09	4	2,690	2.0
iso-Butane	C ₄ H ₁₀	58.12	4	2,957	1.8
n-Butane	C ₄ H ₁₀	58.12	4	2,968	1.8
cis-Butene	C ₄ H ₈	56.11	4	2,830	1.6
iso-Butene	C ₄ H ₈	56.11	4	2,928	1.8
trans-Butene	C ₄ H ₈	56.11	4	2,826	1.7
Carbon Dioxide	CO ₂	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C ₃ H ₆	42.08	3	2,185	2.4
Ethane	C ₂ H ₆	30.07	2	1,595	3.0
Ethylene	C ₂ H ₄	28.05	2	1,477	2.7
Hydrogen	H ₂	2.02	0	1,212 ^a	4.0
Hydrogen Sulfide	H ₂ S	34.08	0	587	4.0
Methane	CH ₄	16.04	1	896	5.0
Methyl- Acetylene	C ₃ H ₄	40.06	3	2,088	1.7
Nitrogen	N ₂	28.01	0	0	∞
Oxygen	O ₂	32.00	0	0	∞
Pentane+ (C5+)	C ₅ H ₁₂	72.15	5	3,655	1.4
Propadiene	C ₃ H ₄	40.06	3	2,066	2.16
Propane	C ₃ H ₈	44.10	3	2,281	2.1
Propylene	C ₃ H ₆	42.08	3	2,150	2.4

Water	H ₂ O	18.02	0	0	∞
-------	------------------	-------	---	---	---

^aThe theoretical net heating value for hydrogen is 274 Btu/scf, but for the purposes of the flare requirement in this subpart, a net heating value of 1,212 Btu/scf shall be used.

Table 13—Calibration and Quality Control Requirements for CPMS

Parameter	Minimum accuracy requirements	Calibration requirements
Temperature	±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor.
		Record the results of each calibration check and inspection.
		Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
Flow Rate for All Flows Other Than Flare Vent Gas	±5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor.
	±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow	At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor.
	±5 percent over the normal range measured for mass flow	Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions

		due to upstream and downstream disturbances.
Flare Vent Gas Flow Rate	<p>±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second)</p> <p>±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second)</p>	<p>Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor.</p> <p>At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor.</p>
		Record the results of each calibration check and inspection.
		Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
Pressure	±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater	<p>Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated.</p> <p>Using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor.</p>
		At least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor.
		Record the results of each calibration check and inspection.
		Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
Net Heating Value by Calorimeter	±2 percent of span	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's

		recommendations at a minimum. Temperature control (heated and/or cooled as necessary) the sampling system to ensure proper year-round operation.
		Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.
Net Heating Value by Gas Chromatograph	As specified in Performance Specification 9 of 40 CFR part 60, appendix B	Follow the procedure in Performance Specification 9 of 40 CFR part 60, appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C).
Hydrogen analyzer	±2 percent over the concentration measured or 0.1 volume percent, whichever is greater	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum.
		Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, 29882, June 12, 1996; 63 FR 44142, 44143, Aug. 18, 1998; 74 FR 55688, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 80 FR 75269, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

Appendix O

Subpart SS—National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

Contents

§63.980 Applicability.
§63.981 Definitions.
§63.982 Requirements.
§63.983 Closed vent systems.
§63.984 Fuel gas systems and processes to which storage vessel, transfer rack, or equipment leak regulated material emissions are routed.
§63.985 Nonflare control devices used to control emissions from storage vessels and low throughput transfer racks.
§63.986 Nonflare control devices used for equipment leaks only.
§63.987 Flare requirements.
§63.988 Incinerators, boilers, and process heaters.
§63.989 [Reserved]
§63.990 Absorbers, condensers, and carbon adsorbers used as control devices.
§63.991 [Reserved]
§63.992 Implementation and enforcement.
§63.993 Absorbers, condensers, carbon adsorbers and other recovery devices used as final recovery devices.
§63.994 Halogen scrubbers and other halogen reduction devices.
§63.995 Other control devices.
§63.996 General monitoring requirements for control and recovery devices.
§63.997 Performance test and compliance assessment requirements for control devices.
§63.998 Recordkeeping requirements.
§63.999 Notifications and other reports.

SOURCE: 64 FR 34866, June 29, 1999, unless otherwise noted.

[↑ Back to Top](#)

§63.980 Applicability.

The provisions of this subpart include requirements for closed vent systems, control devices and routing of air emissions to a fuel gas system or process. These provisions apply when another subpart references the use of this subpart for such air emission control. These air emission standards are placed here for administrative convenience and only apply to those owners and operators of facilities subject to a referencing subpart. The provisions of 40 CFR part 63, subpart A (General Provisions) do not apply to this subpart except as specified in a referencing subpart.

[↑ Back to Top](#)

§63.981 Definitions.

Alternative test method means any method of sampling and analyzing for an air pollutant that is not a reference test or equivalent method, and that has been demonstrated to the Administrator's satisfaction, using Method 301 in appendix A of this part 63, or previously approved by the Administrator prior to the promulgation date of standards for an affected source or affected facility under a referencing subpart, to produce results adequate for the Administrator's determination that it may be used in place of a test method specified in this subpart.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator or a process heater.

By compound means by individual stream components, not carbon equivalents.

Closed vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device. Closed vent system does not include the vapor collection system that is part of any tank truck or railcar.

Closed vent system shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a closed vent system or part of a closed vent system consistent with safety constraints and during which repairs can be effected. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a closed vent system shutdown. An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the closed vent system or part of the closed vent system of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled closed vent system shutdown, is not a closed vent system shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not closed vent system shutdowns.

Combustion device means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of organic emissions.

Continuous parameter monitoring system (CPMS) means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of process or control system parameters.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every 15 minutes and recorded at the frequency specified in §63.998(b).

Control device means, with the exceptions noted below, a combustion device, recovery device, recapture device, or any combination of these devices used to comply with this subpart or a referencing subpart. For process vents from continuous unit operations at affected sources in subcategories where the applicability criteria includes a TRE index value, recovery devices are not considered to be control devices. Primary condensers on steam strippers or fuel gas systems are not considered to be control devices.

Control System means the combination of the closed vent system and the control devices used to collect and control vapors or gases from a regulated emission source.

Day means a calendar day.

Ductwork means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Final recovery device means the last recovery device on a process vent stream from a continuous unit operation at an affected source in a subcategory where the applicability criteria includes a TRE index value. The final recovery device usually discharges to a combustion device, recapture device, or directly to the atmosphere.

First attempt at repair, for the purposes of this subpart, means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere, followed by monitoring as specified in §63.983(c) to verify whether the leak is repaired, unless the owner or operator determines by other means that the leak is not repaired.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is, or whether the valve position would allow gas flow to be, present in a line.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous streams generated by onsite operations, may blend them with other sources of gas, and transports the gaseous streams for use as fuel gas in combustion devices or in-process combustion equipment such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards, such as ANSI B31.3.

High throughput transfer rack means those transfer racks that transfer a total of 11.8 million liters per year or greater of liquid containing regulated material.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. The above energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.

Low throughput transfer rack means those transfer racks that transfer less than a total of 11.8 million liters per year of liquid containing regulated material.

Operating parameter value means a minimum or maximum value established for a control device parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emission limit or operating limit.

Organic monitoring device means a unit of equipment used to indicate the concentration level of organic compounds based on a detection principle such as infra-red, photo ionization, or thermal conductivity.

Owner or operator means any person who owns, leases, operates, controls, or supervises a regulated source or a stationary source of which a regulated source is a part.

Performance level means the level at which the regulated material in the gases or vapors vented to a control or recovery device is removed, recovered, or destroyed. Examples of control device performance levels include: achieving a minimum organic reduction efficiency expressed as a percentage of regulated material removed or destroyed in the control device inlet stream on a weight-basis; achieving an organic concentration in the control device exhaust stream that is less than a maximum allowable limit expressed in parts per million by volume on a dry basis corrected to 3 percent oxygen if a combustion device is the control device and supplemental combustion air is used to combust the emissions; or maintaining appropriate control device operating parameters indicative of the device performance at specified values.

Performance test means the collection of data resulting from the execution of a test method (usually three emission test runs) used to demonstrate compliance with a relevant emission limit as specified in the performance test section of this subpart or in the referencing subpart.

Primary fuel means the fuel that provides the principal heat input to a device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed combustion device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water. A process heater may, as a secondary function, heat water in unfired heat recovery sections.

Recapture device means an individual unit of equipment capable of and used for the purpose of recovering chemicals, but not normally for use, reuse, or sale. For example, a recapture device

may recover chemicals primarily for disposal. Recapture devices include, but are not limited to, absorbers, carbon adsorbers, and condensers. For purposes of the monitoring, recordkeeping and reporting requirements of this subpart, recapture devices are considered recovery devices.

Recovery device means an individual unit of equipment capable of and normally used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse, or for sale for fuel value, use, or reuse. Examples of equipment that may be recovery devices include absorbers, carbon adsorbers, condensers, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers, or thin-film evaporation units. For purposes of the monitoring, recordkeeping, and reporting requirements of this subpart, recapture devices are considered recovery devices.

Recovery operations equipment means the equipment used to separate the components of process streams. Recovery operations equipment includes distillation units, condensers, etc. Equipment used for wastewater treatment shall not be considered recovery operations equipment.

Referencing subpart means the subpart which refers an owner or operator to this subpart.

Regulated material, for purposes of this subpart, refers to vapors from volatile organic liquids (VOL), volatile organic compounds (VOC), or hazardous air pollutants (HAP), or other chemicals or groups of chemicals that are regulated by a referencing subpart.

Regulated source for the purposes of this subpart, means the stationary source, the group of stationary sources, or the portion of a stationary source that is regulated by a relevant standard or other requirement established pursuant to a referencing subpart.

Repaired, for the purposes of this subpart, means that equipment; is adjusted, or otherwise altered, to eliminate a leak as defined in the applicable sections of this subpart; and unless otherwise specified in applicable provisions of this subpart, is inspected as specified in §63.983(c) to verify that emissions from the equipment are below the applicable leak definition.

Routed to a process or route to a process means the gas streams are conveyed to any enclosed portion of a process unit where the emissions are 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.

Run means one of a series of emission or other measurements needed to determine emissions for a representative operating period or cycle as specified in this subpart. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Secondary fuel means a fuel fired through a burner other than the primary fuel burner that provides supplementary heat in addition to the heat provided by the primary fuel.

Sensor means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

Specific gravity monitoring device means a unit of equipment used to monitor specific gravity and having a minimum accuracy of ± 0.02 specific gravity units.

Supplemental combustion air means the air that is added to a vent stream after the vent stream leaves the unit operation. Air that is part of the vent stream as a result of the nature of the unit operation is not considered supplemental combustion air. Air required to operate combustion device burner(s) is not considered supplemental combustion air. Air required to ensure the proper operation of catalytic oxidizers, to include the intermittent addition of air upstream of the catalyst bed to maintain a minimum threshold flow rate through the catalyst bed or to avoid excessive temperatures in the catalyst bed, is not considered to be supplemental combustion air.

Temperature monitoring device means a unit of equipment used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 1.2 degrees Celsius ($^{\circ}\text{C}$), whichever is greater.

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999; 67 FR 46277, July 12, 2002]

[!\[\]\(e78f798d4ea5c530c9db49e7d26e6b95_img.jpg\) Back to Top](#)

§63.982 Requirements.

(a) *General compliance requirements for storage vessels, process vents, transfer racks, and equipment leaks.* An owner or operator who is referred to this subpart for controlling regulated material emissions from storage vessels, process vents, low and high throughput transfer racks, or equipment leaks by venting emissions through a closed vent system to a flare, nonflare control device or routing to a fuel gas system or process shall comply with the applicable requirements of paragraphs (a)(1) through (4) of this section.

(1) *Storage vessels.* The owner or operator shall comply with the applicable provisions of paragraphs (b), (c)(1), and (d) of this section.

(2) *Process vents.* The owner or operator shall comply with the applicable provisions of paragraphs (b), (c)(2), and (e) of this section.

(3) *Transfer racks.* (i) For low throughput transfer racks, the owner or operator shall comply with the applicable provisions of paragraphs (b), (c)(1), and (d) of this section.

(ii) For high throughput transfer racks, the owner or operator shall comply with the applicable provisions of paragraphs (b), (c)(2), and (d) of this section.

(4) *Equipment leaks.* The owner or operator shall comply with the applicable provisions of paragraphs (b), (c)(3), and (d) of this section.

(b) *Closed vent system and flare.* Owners or operators that vent emissions through a closed vent system to a flare shall meet the requirements in §63.983 for closed vent systems; §63.987 for

flares; §63.997 (a), (b) and (c) for provisions regarding flare compliance assessments; the monitoring, recordkeeping, and reporting requirements referenced therein; and the applicable recordkeeping and reporting requirements of §§63.998 and 63.999. No other provisions of this subpart apply to emissions vented through a closed vent system to a flare.

(c) *Closed vent system and nonflare control device.* Owners or operators who control emissions through a closed vent system to a nonflare control device shall meet the requirements in §63.983 for closed vent systems, the applicable recordkeeping and reporting requirements of §§63.998 and 63.999, and the applicable requirements listed in paragraphs (c)(1) through (3) of this section.

(1) For storage vessels and low throughput transfer racks, the owner or operator shall meet the requirements in §63.985 for nonflare control devices and the monitoring, recordkeeping, and reporting requirements referenced therein. No other provisions of this subpart apply to low throughput transfer rack emissions or storage vessel emissions vented through a closed vent system to a nonflare control device unless specifically required in the monitoring plan submitted under §63.985(c).

(2) For process vents and high throughput transfer racks, the owner or operator shall meet the requirements applicable to the control devices being used in §63.988, §63.990 or §63.995; the applicable general monitoring requirements of §63.996 and the applicable performance test requirements and procedures of §63.997; and the monitoring, recordkeeping and reporting requirements referenced therein. Owners or operators subject to halogen reduction device requirements under a referencing subpart must also comply with §63.994 and the monitoring, recordkeeping, and reporting requirements referenced therein. The requirements of §§63.984 through 63.986 do not apply to process vents or high throughput transfer racks.

(3) For equipment leaks, owners or operators shall meet the requirements in §63.986 for nonflare control devices used for equipment leak emissions and the monitoring, recordkeeping, and reporting requirements referenced therein. No other provisions of this subpart apply to equipment leak emissions vented through a closed vent system to a nonflare control device.

(d) *Route to a fuel gas system or process.* Owners or operators that route emissions to a fuel gas system or to a process shall meet the requirements in §63.984, the monitoring, recordkeeping, and reporting requirements referenced therein, and the applicable recordkeeping and reporting requirements of §§63.998 and 63.999. No other provisions of this subpart apply to emissions being routed to a fuel gas system or process.

(e) *Final recovery devices.* Owners or operators who use a final recovery device to maintain a TRE above a level specified in a referencing subpart shall meet the requirements in §63.993 and the monitoring, recordkeeping, and reporting requirements referenced therein that are applicable to the recovery device being used; the applicable monitoring requirements in §63.996 and the recordkeeping and reporting requirements referenced therein; and the applicable recordkeeping and reporting requirements of §§63.998 and 63.999. No other provisions of this subpart apply to process vent emissions routed to a final recovery device.

(f) *Combined emissions.* When emissions from different emission types (e.g., emissions from process vents, transfer racks, and/or storage vessels) are combined, an owner or operator shall comply with the requirements of either paragraph (f)(1) or (2) of this section.

(1) Comply with the applicable requirements of this subpart for each kind of emissions in the stream (e.g., the requirements of paragraph (a)(2) of this section for process vents, and the requirements of paragraph (a)(3) of this section for transfer racks); or

(2) Comply with the first set of requirements identified in paragraphs (f)(2)(i) through (iii) of this section which applies to any individual emission stream that is included in the combined stream. Compliance with paragraphs (f)(2)(i) through (iii) of this section constitutes compliance with all other emissions requirements for other emission streams.

(i) The requirements of §63.982(a)(2) for process vents, including applicable monitoring, recordkeeping, and reporting;

(ii) The requirements of §63.982(a)(3)(ii) for high throughput transfer racks, including applicable monitoring, recordkeeping, and reporting;

(iii) The requirements of §63.982(a)(1) or (a)(3)(i) for control of emissions from storage vessels or low throughput transfer racks, including applicable monitoring, recordkeeping, and reporting.

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999]

[↑ Back to Top](#)

§63.983 Closed vent systems.

(a) *Closed vent system equipment and operating requirements.* Except for closed vent systems operated and maintained under negative pressure, the provisions of this paragraph apply to closed vent systems collecting regulated material from a regulated source.

(1) *Collection of emissions.* Each closed vent system shall be designed and operated to collect the regulated material vapors from the emission point, and to route the collected vapors to a control device.

(2) *Period of operation.* Closed vent systems used to comply with the provisions of this subpart shall be operated at all times when emissions are vented to, or collected by, them.

(3) *Bypass monitoring.* Except for equipment needed for safety purposes such as pressure relief devices, low leg drains, high point bleeds, analyzer vents, and open-ended valves or lines, the owner or operator shall comply with the provisions of either paragraphs (a)(3)(i) or (ii) of this section for each closed vent system that contains bypass lines that could divert a vent stream to the atmosphere.

(i) Properly install, maintain, and operate a flow indicator that is capable of taking periodic readings. Records shall be generated as specified in §63.998(d)(1)(ii)(A). The flow indicator shall be installed at the entrance to any bypass line.

(ii) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. Records shall be generated as specified in §63.998(d)(1)(ii)(B).

(4) *Loading arms at transfer racks.* Each closed vent system collecting regulated material from a transfer rack shall be designed and operated so that regulated material vapors collected at one loading arm will not pass through another loading arm in the rack to the atmosphere.

(5) *Pressure relief devices in a transfer rack's closed vent system.* The owner or operator of a transfer rack subject to the provisions of this subpart shall ensure that no pressure relief device in the transfer rack's closed vent system shall open to the atmosphere during loading. Pressure relief devices needed for safety purposes are not subject to this paragraph.

(b) *Closed vent system inspection and monitoring requirements.* The provisions of this subpart apply to closed vent systems collecting regulated material from a regulated source. Inspection records shall be generated as specified in §63.998(d)(1)(iii) and (iv) of this section.

(1) Except for any closed vent systems that are designated as unsafe or difficult to inspect as provided in paragraphs (b)(2) and (3) of this section, each closed vent system shall be inspected as specified in paragraph (b)(1)(i) or (ii) of this section.

(i) If the closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (b)(1)(i)(A) and (B) of this section.

(A) Conduct an initial inspection according to the procedures in paragraph (c) of this section; and

(B) Conduct annual inspections for visible, audible, or olfactory indications of leaks.

(ii) If the closed vent system is constructed of ductwork, the owner or operator shall conduct an initial and annual inspection according to the procedures in paragraph (c) of this section.

(2) Any parts of the closed vent system that are designated, as described in §63.998(d)(1)(i), as unsafe to inspect are exempt from the inspection requirements of paragraph (b)(1) of this section if the conditions of paragraphs (b)(2)(i) and (ii) of this section are met.

(i) The owner or operator determines 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 paragraph (b)(1) of this section; and

(ii) The owner or operator has a written plan that requires inspection of the equipment as frequently as practical during safe-to-inspect times. Inspection is not required more than once annually.

(3) Any parts of the closed vent system that are designated, as described in §63.998(d)(1)(i), as difficult-to-inspect are exempt from the inspection requirements of paragraph (b)(1) of this section if the provisions of paragraphs (b)(3)(i) and (ii) of this section apply.

(i) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters (7 feet) above a support surface; and

(ii) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

(4) For each bypass line, the owner or operator shall comply with paragraph (b)(4)(i) or (ii) of this section.

(i) If a flow indicator is used, take a reading at least once every 15 minutes.

(ii) If the bypass line valve is secured in the non-diverting position, 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 line.

(c) *Closed vent system inspection procedures.* The provisions of this paragraph apply to closed vent systems collecting regulated material from a regulated source.

(1) Each closed vent system subject to this paragraph shall be inspected according to the procedures specified in paragraphs (c)(1)(i) through (vii) of this section.

(i) Inspections shall be conducted in accordance with Method 21 of 40 CFR part 60, appendix A, except as specified in this section.

(ii) Except as provided in (c)(1)(iii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the representative composition of the process fluid and not of each individual VOC in the stream. For process streams that contain nitrogen, air, water, or other inerts that are not organic HAP or VOC, the representative stream response factor must be determined on an inert-free basis. The response factor may be determined at any concentration for which the monitoring for leaks will be conducted.

(iii) If no instrument is available at the plant site that will meet the performance criteria of Method 21 specified in paragraph (c)(1)(ii) of this section, the instrument readings may be adjusted by multiplying by the representative response factor of the process fluid, calculated on an inert-free basis as described in paragraph (c)(1)(ii) of this section.

(iv) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21 of 40 CFR part 60, appendix A.

(v) Calibration gases shall be as specified in paragraphs (c)(1)(v)(A) through (C) of this section.

(A) Zero air (less than 10 parts per million hydrocarbon in air); and

(B) Mixtures of methane in air at a concentration less than 10,000 parts per million. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (c)(1)(ii) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(C) If the detection instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,500 parts per million.

(vi) An owner or operator may elect to adjust or not adjust instrument readings for background. If an owner or operator elects not to adjust readings for background, all such instrument readings shall be compared directly to 500 parts per million to determine whether there is a leak. If an owner or operator elects to adjust instrument readings for background, the owner or operator shall measure background concentration using the procedures in this section. The owner or operator shall subtract the background reading from the maximum concentration indicated by the instrument.

(vii) If the owner or operator elects to adjust for background, the arithmetic difference between the maximum concentration indicated by the instrument and the background level shall be compared with 500 parts per million for determining whether there is a leak.

(2) The instrument probe shall be traversed around all potential leak interfaces as described in Method 21 of 40 CFR part 60, appendix A.

(3) Except as provided in paragraph (c)(4) of this section, inspections shall be performed when the equipment is in regulated material service, or in use with any other detectable gas or vapor.

(4) Inspections of the closed vent system collecting regulated material from a transfer rack shall be performed only while a tank truck or railcar is being loaded or is otherwise pressurized to normal operating conditions with regulated material or any other detectable gas or vapor.

(d) *Closed vent system leak repair provisions.* The provisions of this paragraph apply to closed vent systems collecting regulated material from a regulated source.

(1) If there are visible, audible, or olfactory indications of leaks at the time of the annual visual inspections required by paragraph (b)(1)(i)(B) of this section, the owner or operator shall follow the procedure specified in either paragraph (d)(1)(i) or (ii) of this section.

(i) The owner or operator shall eliminate the leak.

(ii) The owner or operator shall monitor the equipment according to the procedures in paragraph (c) of this section.

(2) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practical, except as provided in paragraph (d)(3) of this section. Records shall be generated as specified in §63.998(d)(1)(iii) when a leak is detected.

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

(ii) Except as provided in paragraph (d)(3) of this section, repairs shall be completed no later than 15 days after the leak is detected or at the beginning of the next introduction of vapors to the system, whichever is later.

(3) Delay of repair of a closed vent system for which leaks have been detected is allowed if repair within 15 days after a leak is detected is technically infeasible or unsafe without a closed vent system shutdown, as defined in §63.981, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed as soon as practical, but not later than the end of the next closed vent system shutdown.

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999; 67 FR 46277, July 12, 2002]

[↑ Back to Top](#)

§63.984 Fuel gas systems and processes to which storage vessel, transfer rack, or equipment leak regulated material emissions are routed.

(a) *Equipment and operating requirements for fuel gas systems and processes.* (1) Except during periods of start-up, shutdown and malfunction as specified in the referencing subpart, the fuel gas system or process shall be operating at all times when regulated material emissions are routed to it.

(2) The owner or operator of a transfer rack subject to the provisions of this subpart shall ensure that no pressure relief device in the transfer rack's system returning vapors to a fuel gas system or process shall open to the atmosphere during loading. Pressure relief devices needed for safety purposes are not subject to this paragraph.

(b) *Fuel gas system and process compliance assessment.* (1) If emissions are routed to a fuel gas system, there is no requirement to conduct a performance test or design evaluation.

(2) If emissions are routed to a process, the regulated material in the emissions shall meet one or more of the conditions specified in paragraphs (b)(2)(i) through (iv) of this section. The owner or operator of storage vessels subject to this paragraph shall comply with the compliance demonstration requirements in paragraph (b)(3) of this section.

(i) Recycled and/or consumed in the same manner as a material that fulfills the same function in that process;

(ii) Transformed by chemical reaction into materials that are not regulated materials;

(iii) Incorporated into a product; and/or

(iv) Recovered.

(3) To demonstrate compliance with paragraph (b)(2) of this section for a storage vessel, the owner or operator shall prepare a design evaluation (or engineering assessment) that demonstrates the extent to which one or more of the conditions specified in paragraphs (b)(2)(i) through (iv) of this section are being met.

(c) *Statement of connection.* For storage vessels and transfer racks, the owner or operator shall submit the statement of connection reports for fuel gas systems specified in §63.999(b)(1)(ii), as appropriate.

[↑ Back to Top](#)

§63.985 Nonflare control devices used to control emissions from storage vessels and low throughput transfer racks.

(a) *Nonflare control device equipment and operating requirements.* The owner or operator shall operate and maintain the nonflare control device so that the monitored parameters defined as required in paragraph (c) of this section remain within the ranges specified in the Notification of Compliance Status whenever emissions of regulated material are routed to the control device except during periods of start-up, shutdown, and malfunction as specified in the referencing subpart.

(b) *Nonflare control device design evaluation or performance test requirements.* When using a control device other than a flare, the owner or operator shall comply with the requirements in paragraphs (b)(1)(i) or (ii) of this section, except as provided in paragraphs (b)(2) and (3) of this section.

(1) *Design evaluation or performance test results.* The owner or operator shall prepare and submit with the Notification of Compliance Status, as specified in §63.999(b)(2), either a design evaluation that includes the information specified in paragraph (b)(1)(i) of this section, or the results of the performance test as described in paragraph (b)(1)(ii) of this section.

(i) *Design evaluation.* The design evaluation shall include documentation demonstrating that the control device being used achieves the required control efficiency during the reasonably expected maximum storage vessel filling or transfer loading rate. This documentation is to include a description of the gas stream that enters the control device, including flow and regulated material content, and the information specified in paragraphs (b)(1)(i)(A) through (E)

of this section, as applicable. For storage vessels, the description of the gas stream that enters the control device shall be provided for varying liquid level conditions. This documentation shall be submitted with the Notification of Compliance Status as specified in §63.999(b)(2).

(A) The efficiency determination is to include consideration of all vapors, gases, and liquids, other than fuels, received by the control device.

(B) If an enclosed combustion device with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C is used to meet an emission reduction requirement specified in a referencing subpart for storage vessels and transfer racks, documentation that those conditions exist is sufficient to meet the requirements of paragraph (b)(1)(i) of this section.

(C) Except as provided in paragraph (b)(1)(i)(B) of this section for enclosed combustion devices, the design evaluation shall include the estimated autoignition temperature of the stream being combusted, the flow rate of the stream, the combustion temperature, and the residence time at the combustion temperature.

(D) For carbon adsorbers, the design evaluation shall include the estimated affinity of the regulated material vapors for carbon, the amount of carbon in each bed, the number of beds, the humidity, the temperature, the flow rate of the inlet stream and, if applicable, the desorption schedule, the regeneration stream pressure or temperature, and the flow rate of the regeneration stream. For vacuum desorption, pressure drop shall be included.

(E) For condensers, the design evaluation shall include the final temperature of the stream vapors, the type of condenser, and the design flow rate of the emission stream.

(ii) *Performance test.* A performance test, whether conducted to meet the requirements of this section, or to demonstrate compliance for a process vent or high throughput transfer rack as required by §63.988(b), §63.990(b), or §63.995(b), is acceptable to demonstrate compliance with emission reduction requirements for storage vessels and transfer racks. The owner or operator is not required to prepare a design evaluation for the control device as described in paragraph (b)(1)(i) of this section if a performance test will be performed that meets the criteria specified in paragraphs (b)(1)(ii)(A) and (B) of this section.

(A) The performance test will demonstrate that the control device achieves greater than or equal to the required control device performance level specified in a referencing subpart for storage vessels or transfer racks; and

(B) The performance test meets the applicable performance test requirements and the results are submitted as part of the Notification of Compliance Status as specified in §63.999(b)(2).

(2) *Exceptions.* A design evaluation or performance test is not required if the owner or operator uses a combustion device meeting the criteria in paragraph (b)(2)(i), (ii), (iii), or (iv) of this section.

(i) A boiler or process heater with a design heat input capacity of 44 megawatts (150 million British thermal units per hour) or greater.

(ii) A boiler or process heater burning hazardous waste for which the owner or operator meets the requirements specified in paragraph (b)(2)(ii)(A) or (B) of this section.

(A) The boiler or process heater has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or

(B) The boiler or process heater has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(iii) A hazardous waste incinerator for which the owner or operator meets the requirements specified in paragraph (b)(2)(iii)(A) or (B) of this section.

(A) The incinerator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or

(B) The incinerator has certified compliance with the interim status requirements of 40 CFR part 265, subpart O; or

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

(3) *Prior design evaluations or performance tests.* If a design evaluation or performance test is required in the referencing subpart or was previously conducted and submitted for a storage vessel or low throughput transfer rack, then a performance test or design evaluation is not required.

(c) *Nonflare control device monitoring requirements.* (1) The owner or operator shall submit with the Notification of Compliance Status, a monitoring plan containing the information specified in §63.999(b)(2)(i) and (ii) to identify the parameters that will be monitored to assure proper operation of the control device.

(2) The owner or operator shall monitor the parameters specified in the Notification of Compliance Status or in the operating permit application or amendment. Records shall be generated as specified in §63.998(d)(2)(i).

[↑ Back to Top](#)

§63.986 Nonflare control devices used for equipment leaks only.

(a) *Equipment and operating requirements.* (1) Owners or operators using a nonflare control device to meet the applicable requirements of a referencing subpart for equipment leaks shall meet the requirements of this section.

(2) Control devices used to comply with the provisions of this subpart shall be operated at all times when emissions are vented to them.

(b) *Performance test requirements.* A performance test is not required for any nonflare control device used only to control emissions from equipment leaks.

(c) *Monitoring requirements.* Owners or operators of control devices that are used to comply only with the provisions of a referencing subpart for control of equipment leak emissions shall monitor these control devices to ensure that they are operated and maintained in conformance with their design. The owner or operator shall maintain the records as specified in §63.998(d)(4).

[↑ Back to Top](#)

§63.987 Flare requirements.

(a) *Flare equipment and operating requirements.* Flares subject to this subpart shall meet the performance requirements in 40 CFR 63.11(b) (General Provisions).

(b) *Flare compliance assessment.* (1) The owner or operator shall conduct an initial flare compliance assessment of any flare used to comply with the provisions of this subpart. Flare compliance assessment records shall be kept as specified in §63.998(a)(1) and a flare compliance assessment report shall be submitted as specified in §63.999(a)(2). An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet regulated material or total organic compound concentration when a flare is used.

(2) [Reserved]

(3) Flare compliance assessments shall meet the requirements specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) Method 22 of appendix A of part 60 shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours, except for transfer racks as provided in (b)(3)(i)(A) or (B) of this section.

(A) For transfer racks, if the loading cycle is less than 2 hours, then the observation period for that run shall be for the entire loading cycle.

(B) For transfer racks, if additional loading cycles are initiated within the 2-hour period, then visible emissions observations shall be conducted for the additional cycles.

(ii) The net heating value of the gas being combusted in a flare shall be calculated using Equation 1:

$$H_T = K_1 \sum_{j=1}^n D_j H_j \quad [Eq. 1]$$

[View or download PDF](#)

Where:

H_T = Net heating value of the sample, megajoules per standard cubic meter; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 millimeters of mercury (30 inches of mercury), but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$K_1 = 1.740 \times 10^{-7}$ (parts per million by volume)⁻¹ (gram-mole per standard cubic meter) (megajoules per kilocalories), where the standard temperature for gram mole per standard cubic meter is 20 °C;

n = number of sample components;

D_j = Concentration of sample component j , in parts per million by volume on a wet basis, as measured for organics by Method 18 of 40 CFR part 60, appendix A, or by American Society for Testing and Materials (ASTM) D6420-99 (available for purchase from at least one of the following addresses: 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959; or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106) under the conditions specified in §63.997(e)(2)(iii)(D)(1) through (3). Hydrogen and carbon monoxide are measured by ASTM D1946-90; and

H_j = Net heat of combustion of sample component j , kilocalories per gram mole at 25 °C and 760 millimeters of mercury (30 inches of mercury).

(iii) The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate (in unit of standard temperature and pressure), as determined by Method 2, 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, as appropriate, by the unobstructed (free) cross sectional area of the flare tip.

(iv) Flare flame or pilot monitors, as applicable, shall be operated during any flare compliance assessment.

(c) *Flare monitoring requirements.* Where a flare is used, the following monitoring equipment is required: a device (including but not limited to a thermocouple, ultra-violet beam sensor, or infrared sensor) capable of continuously detecting that at least one pilot flame or the flare flame is present. Flare flame monitoring and compliance records shall be kept as specified in §63.998(a)(1) and reported as specified in §63.999(a).

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999; 67 FR 46277, July 12, 2002]

[↑ Back to Top](#)

§63.988 Incinerators, boilers, and process heaters.

(a) *Equipment and operating requirements.* (1) Owners or operators using incinerators, boilers, or process heaters to meet a weight-percent emission reduction or parts per million by volume outlet concentration requirement specified in a referencing subpart shall meet the requirements of this section.

(2) Incinerators, boilers, or process heaters used to comply with the provisions of a referencing subpart and this subpart shall be operated at all times when emissions are vented to them.

(3) For boilers and process heaters, the vent stream shall be introduced into the flame zone of the boiler or process heater.

(b) *Performance test requirements.* (1) Except as specified in §63.997(b), and paragraph (b)(2) of this section, the owner or operator shall conduct an initial performance test of any incinerator, boiler, or process heater used to comply with the provisions of a referencing subpart and this subpart according to the procedures in §63.997. Performance test records shall be kept as specified in §63.998(a)(2) and a performance test report shall be submitted as specified in §63.999(a)(2). As provided in §63.985(b)(1), a design evaluation may be used as an alternative to the performance test for storage vessels and low throughput transfer rack controls. As provided in §63.986(b), no performance test is required for equipment leaks.

(2) An owner or operator is not required to conduct a performance test when any of the control devices specified in paragraphs (b)(2)(i) through (iv) of this section are used.

(i) A hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O;

(ii) A boiler or process heater with a design heat input capacity of 44 megawatts (150 million British thermal units per hour) or greater;

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

(iv) A boiler or process heater burning hazardous waste for which the owner or operator meets the requirements specified in paragraph (b)(2)(iv)(A) or (B) of this section.

(A) The boiler or process heater has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or

(B) The boiler or process heater has certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(c) *Incinerator, boiler, and process heater monitoring requirements.* Where an incinerator, boiler, or process heater is used, a temperature monitoring device capable of providing a continuous record that meets the provisions specified in paragraph (c)(1), (2), or (3) of this section is required. Any boiler or process heater in which all vent streams are introduced with

primary fuel or are used as the primary fuel is exempt from monitoring. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in the referencing subpart and §3.996.

(1) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the fire box or in the ductwork immediately downstream of the fire box in a position before any substantial heat exchange occurs.

(2) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(3) Where a boiler or process heater of less than 44 megawatts (150 million British thermal units per hour) design heat input capacity is used and the regulated vent stream is not introduced as or with the primary fuel, a temperature monitoring device shall be installed in the fire box.

[↑ Back to Top](#)

§63.989 [Reserved]

[↑ Back to Top](#)

§63.990 Absorbers, condensers, and carbon adsorbers used as control devices.

(a) *Equipment and operating requirements.* (1) Owners or operators using absorbers, condensers, or carbon adsorbers to meet a weight-percent emission reduction or parts per million by volume outlet concentration requirement specified in a referencing subpart shall meet the requirements of this section.

(2) Absorbers, condensers, and carbon adsorbers used to comply with the provisions of a referencing subpart and this subpart shall be operated at all times when emissions are vented to them.

(b) *Performance test requirements.* Except as specified in §63.997(b), the owner or operator shall conduct an initial performance test of any absorber, condenser, or carbon adsorber used as a control device to comply with the provisions of the referencing subpart and this subpart according to the procedures in §63.997. Performance test records shall be kept as specified in §63.998(a)(2) and a performance test report shall be submitted as specified in §63.999(a)(2). As provided in §63.985(b)(1), a design evaluation may be used as an alternative to the performance test for storage vessels and low throughput transfer rack controls. As provided in §63.986(b), no performance test is required to demonstrate compliance for equipment leaks.

(c) *Monitoring requirements.* Where an absorber, condenser, or carbon adsorber is used as a control device, either an organic monitoring device capable of providing a continuous record, or

the monitoring devices specified in paragraphs (c)(1) through (3), as applicable, shall be used. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in a referencing subpart and §63.996.

(1) Where an absorber is used, a scrubbing liquid temperature monitoring device and a specific gravity monitoring device, each capable of providing a continuous record, shall be used. If the difference between the specific gravity of the saturated scrubbing fluid and specific gravity of the fresh scrubbing fluid is less than 0.02 specific gravity units, an organic monitoring device capable of providing a continuous record shall be used.

(2) Where a condenser is used, a condenser exit (product side) temperature monitoring device capable of providing a continuous record shall be used.

(3) Where a carbon adsorber is used, an integrating regeneration stream flow monitoring device having an accuracy of ± 10 percent or better, capable of recording the total regeneration stream mass or volumetric flow for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the carbon bed temperature after each regeneration and within 15 minutes of completing any cooling cycle, shall be used.

[↑ Back to Top](#)

§63.991 [Reserved]

[↑ Back to Top](#)

§63.992 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (EPA), or a delegated authority such as the applicable State, local, or tribal agency. If the EPA Administrator has delegated authority to a State, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. Contact the applicable EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency.

(1) Approval of alternatives to the nonopacity emissions standards in §§63.983(a) and (d), 63.984, 63.985(a), 63.986(a), 63.987(a), 63.988(a), 63.990(a), 63.993(a), 63.994(a), and 63.995(a) under §63.6(g). Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart.

(2) [Reserved]

(3) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[67 FR 46277, July 12, 2002]

[↑ Back to Top](#)

§63.993 Absorbers, condensers, carbon adsorbers and other recovery devices used as final recovery devices.

(a) *Final recovery device equipment and operating requirements.* (1) Owners or operators using a final recovery device to maintain a TRE above a level specified in a referencing subpart shall meet the requirements of this section.

(2) Recovery devices used to comply with the provisions of a referencing subpart and this subpart shall be operated at all times when emissions are vented to them.

(b) *Recovery device performance test requirements.* There are no performance test requirements for recovery devices. TRE index value determination information shall be recorded as specified in §63.998(a)(3).

(c) *Recovery device monitoring requirements.* (1) Where an absorber is the final recovery device in the recovery system and the TRE index value is between the level specified in a referencing subpart and 4.0, either an organic monitoring device capable of providing a continuous record or a scrubbing liquid temperature monitoring device and a specific gravity monitoring device, each capable of providing a continuous record, shall be used. If the difference between the specific gravity of the saturated scrubbing fluid and specific gravity of the fresh scrubbing fluid is less than 0.02 specific gravity units, an organic monitoring device capable of providing a continuous record shall be used. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in §63.996.

(2) Where a condenser is the final recovery device in the recovery system and the TRE index value is between the level specified in a referencing subpart and 4.0, an organic monitoring device capable of providing a continuous record or a condenser exit (product side) temperature monitoring device capable of providing a continuous record shall be used. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in a referencing subpart and §63.996.

(3) Where a carbon adsorber is the final recovery device in the recovery system and the TRE index value is between the level specified in a referencing subpart and 4.0, an organic monitoring device capable of providing a continuous record or an integrating regeneration stream flow monitoring device having an accuracy of ± 10 percent or better, capable of recording the total regeneration stream mass or volumetric flow for each regeneration cycle; and a carbon-bed temperature monitoring device, capable of recording the carbon-bed temperature after each regeneration and within 15 minutes of completing any cooling cycle shall be used. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in a referencing subpart and §63.996.

(4) If an owner or operator uses a recovery device other than those listed in this subpart, the owner or operator shall submit a description of planned monitoring, reporting and recordkeeping procedures as specified in a referencing subpart. The Administrator will approve, deny, or modify based on the reasonableness of the proposed monitoring, reporting and recordkeeping requirements as part of the review of the submission or permit application or by other appropriate means.

[↑ Back to Top](#)

§63.994 Halogen scrubbers and other halogen reduction devices.

(a) Halogen scrubber and other halogen reduction device equipment and operating requirements. (1) An owner or operator of a halogen scrubber or other halogen reduction device subject to this subpart shall reduce the overall emissions of hydrogen halides and halogens by the control device performance level specified in a referencing subpart.

(2) Halogen scrubbers and other halogen reduction devices used to comply with the provisions of a referencing subpart and this subpart shall be operated at all times when emissions are vented to them.

(b) Halogen scrubber and other halogen reduction device performance test requirements. (1) An owner or operator of a combustion device followed by a halogen scrubber or other halogen reduction device to control halogenated vent streams in accordance with a referencing subpart and this subpart shall conduct an initial performance test to determine compliance with the control efficiency or emission limits for hydrogen halides and halogens according to the procedures in §63.997. Performance test records shall be kept as specified in §63.998(a)(2) and a performance test report shall be submitted as specified in §63.999(a)(2).

(2) An owner or operator of a halogen scrubber or other halogen reduction technique used to reduce the vent stream halogen atom mass emission rate prior to a combustion device to comply with a performance level specified in a referencing subpart shall determine the halogen atom mass emission rate prior to the combustion device according to the procedures specified in the

referencing subpart. Records of the halogen concentration in the vent stream shall be generated as specified in §63.998(a)(4).

(c) *Halogen scrubber and other halogen reduction device monitoring requirements.* (1) Where a halogen scrubber is used, the monitoring equipment specified in paragraphs (c)(1)(i) and (ii) of this section is required for the scrubber. Monitoring results shall be recorded as specified in §63.998(b) and (c), as applicable. General requirements for monitoring and continuous parameter monitoring systems are contained in a referencing subpart and §63.996.

(i) A pH monitoring device capable of providing a continuous record shall be installed to monitor the pH of the scrubber effluent.

(ii) A flow meter capable of providing a continuous record shall be located at the scrubber influent for liquid flow. Gas stream flow shall be determined using one of the procedures specified in paragraphs (c)(1)(ii)(A) through (D) of this section.

(A) The owner or operator may determine gas stream flow using the design blower capacity, with appropriate adjustments for pressure drop.

(B) The owner or operator may measure the gas stream flow at the scrubber inlet.

(C) If the scrubber is subject to regulations in 40 CFR parts 264 through 266 that have required a determination of the liquid to gas (L/G) ratio prior to the applicable compliance date for the process unit of which it is part as specified in a referencing subpart, the owner or operator may determine gas stream flow by the method that had been utilized to comply with those regulations. A determination that was conducted prior to that compliance date may be utilized to comply with this subpart if it is still representative.

(D) The owner or operator may prepare and implement a gas stream flow determination plan that documents an appropriate method that will be used to determine the gas stream flow. The plan shall require determination of gas stream flow by a method that will at least provide a value for either a representative or the highest gas stream flow anticipated in the scrubber during representative operating conditions other than start-ups, shutdowns, or malfunctions. The plan shall include a description of the methodology to be followed and an explanation of how the selected methodology will reliably determine the gas stream flow, and a description of the records that will be maintained to document the determination of gas stream flow. The owner or operator shall maintain the plan as specified in a referencing subpart.

(2) Where a halogen reduction device other than a scrubber is used, the owner or operator shall follow the procedures specified in a referencing subpart in order to establish monitoring parameters.

[!\[\]\(8bba887393ca45b761e5cb49e755e762_img.jpg\) Back to Top](#)

§63.995 Other control devices.

(a) *Other control device equipment and operating requirements.* (1) Owners or operators using a control device other than one listed in §§63.985 through 63.990 to meet a weight-percent emission reduction or parts per million by volume outlet concentration requirement specified in a referencing subpart shall meet the requirements of this section.

(2) Other control devices used to comply with the provisions of a referencing subpart and this subpart shall be operated at all times when emissions are vented to them.

(b) *Other control device performance test requirements.* An owner or operator using a control device other than those specified in §§63.987 through 63.990 to comply with a performance level specified in a referencing subpart, shall perform an initial performance test according to the procedures in §63.997. Performance test records shall be kept as specified in §63.998(a)(2) and a performance test report shall be submitted as specified in §63.999(a)(2).

(c) *Other control device monitoring requirements.* If an owner or operator uses a control device other than those listed in this subpart, the owner or operator shall submit a description of planned monitoring, recordkeeping and reporting procedures as specified in a referencing subpart. The Administrator will approve, deny, or modify based on the reasonableness of the proposed monitoring, reporting and recordkeeping requirements as part of the review of the submission or permit application or by other appropriate means.

[↑ Back to Top](#)

§63.996 General monitoring requirements for control and recovery devices.

(a) *General monitoring requirements applicability.* (1) This section applies to the owner or operator of a regulated source required to monitor under this subpart.

(2) Flares subject to §63.987(c) are not subject to the requirements of this section.

(3) Flow indicators are not subject to the requirements of this section.

(b) *Conduct of monitoring.* (1) Monitoring shall be conducted as set forth in this section and in the relevant sections of this subpart unless the provision in either paragraph (b)(1)(i) or (ii) of this section applies.

(i) The Administrator specifies or approves the use of minor changes in methodology for the specified monitoring requirements and procedures; or

(ii) The Administrator approves the use of alternatives to any monitoring requirements or procedures as provided in the referencing subpart or paragraph (d) of this section.

(2) When one CPMS is used as a backup to another CPMS, the owner or operator shall report the results from the CPMS used to meet the monitoring requirements of this subpart. If both such

CPMS's are used during a particular reporting period to meet the monitoring requirements of this subpart, then the owner or operator shall report the results from each CPMS for the time during the six month period that the instrument was relied upon to demonstrate compliance.

(c) *Operation and maintenance of continuous parameter monitoring systems.* (1) All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately.

(2) The owner or operator of a regulated source shall maintain and operate each CPMS as specified in this section, or in a relevant subpart, and in a manner consistent with good air pollution control practices.

(i) The owner or operator of a regulated source shall ensure the immediate repair or replacement of CPMS parts to correct "routine" or otherwise predictable CPMS malfunctions. The necessary parts for routine repairs of the affected equipment shall be readily available.

(ii) If under the referencing subpart, an owner or operator has developed a start-up, shutdown, and malfunction plan, the plan is followed, and the CPMS is repaired immediately, this action shall be recorded as specified in §63.998(c)(1)(ii)(E).

(iii) The Administrator's determination of whether acceptable operation and maintenance procedures are being used for the CPMS will be based on information that may include, but is not limited to, review of operation and maintenance procedures, operation and maintenance records as specified in §63.998(c)(1)(i) and (ii), manufacturer's recommendations and specifications, and inspection of the CPMS.

(3) All CPMS's shall be installed and operational, and the data verified as specified in this subpart either prior to or in conjunction with conducting performance tests. Verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately.

(4) All CPMS's shall be installed such that representative measurements of parameters from the regulated source are obtained.

(5) In accordance with the referencing subpart, except for system breakdowns, repairs, maintenance periods, instrument adjustments, or checks to maintain precision and accuracy, calibration checks, and zero and span adjustments, all continuous parameter monitoring systems shall be in continuous operation when emissions are being routed to the monitored device.

(6) The owner or operator shall establish a range for monitored parameters that indicates proper operation of the control or recovery device. In order to establish the range, the information required in §63.999(b)(3) shall be submitted in the Notification of Compliance Status or the operating permit application or amendment. The range may be based upon a prior performance

test meeting the specifications of §63.997(b)(1) or a prior TRE index value determination, as applicable, or upon existing ranges or limits established under a referencing subpart. Where the regeneration stream flow and carbon bed temperature are monitored, the range shall be in terms of the total regeneration stream flow per regeneration cycle and the temperature of the carbon bed determined within 15 minutes of the completion of the regeneration cooling cycle.

(d) *Alternatives to monitoring requirements*—(1) *Alternatives to the continuous operating parameter monitoring and recordkeeping provisions.* An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in §§63.988(c), 63.990(c), 63.993(c), 63.994(c), 63.998(a)(2) through (4), 63.998(c)(2) and (3), as specified in §63.999(d)(1).

(2) *Monitoring a different parameter than those listed.* An owner or operator may request approval to monitor a different parameter than those established in paragraph (c)(6) of this section or to set unique monitoring parameters if directed by §63.994(c)(2) or §63.995(c), as specified in §63.999(d)(2).

[↑ Back to Top](#)

§63.997 Performance test and compliance assessment requirements for control devices.

(a) *Performance tests and flare compliance assessments.* Where §§63.985 through 63.995 require, or the owner or operator elects to conduct, a performance test of a control device or a halogen reduction device, or a compliance assessment for a flare, the requirements of paragraphs (b) through (d) of this section apply.

(b) *Prior test results and waivers.* Initial performance tests and initial flare compliance assessments are required only as specified in this subpart or a referencing subpart.

(1) Unless requested by the Administrator, an owner or operator is not required to conduct a performance test or flare compliance assessment under this subpart if a prior performance test or compliance assessment was conducted using the same methods specified in §63.997(e) or §63.987(b)(3), as applicable, and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test or compliance demonstration, with or without adjustments, reliably demonstrate compliance despite process changes. An owner or operator may request permission to substitute a prior performance test or compliance assessment by written application to the Administrator as specified in §63.999(a)(1)(iv).

(2) Individual performance tests and flare compliance assessments may be waived upon written application to the Administrator, per §63.999(a)(1)(iii), if, in the Administrator's judgment, the source is meeting the relevant standard(s) on a continuous basis, the source is being operated under an extension or waiver of compliance, or the owner or operator has requested an extension or waiver of compliance and the Administrator is still considering that request.

(3) Approval of any waiver granted under this section shall not abrogate the Administrator's authority under the Act or in any way prohibit the Administrator from later canceling the waiver. The cancellation will be made only after notification is given to the owner or operator of the source.

(c) Performance tests and flare compliance assessments schedule. (1) Unless a waiver of performance testing or flare compliance assessment is obtained under this section or the conditions of a referencing subpart, the owner or operator shall perform such tests as specified in paragraphs (c)(1)(i) through (vii) of this section.

(i) Within 180 days after the effective date of a relevant standard for a new source that has an initial start-up date before the effective date of that standard; or

(ii) Within 180 days after initial start-up for a new source that has an initial start-up date after the effective date of a relevant standard; or

(iii) Within 180 days after the compliance date specified in a referencing subpart for an existing source, or within 180 days after start-up of an existing source if the source begins operation after the effective date of the relevant emission standard; or

(iv) Within 180 days after the compliance date for an existing source subject to an emission standard established pursuant to section 112(f) of the Act; or

(v) Within 180 days after the termination date of the source's extension of compliance or a waiver of compliance for an existing source that obtains an extension of compliance under §63.1112(a), or waiver of compliance under 40 CFR 61.11; or

(vi) Within 180 days after the compliance date for a new source, subject to an emission standard established pursuant to section 112(f) of the Act, for which construction or reconstruction is commenced after the proposal date of a relevant standard established pursuant to section 112(d) of the Act but before the proposal date of the relevant standard established pursuant to section 112(f); or

(vii) When the promulgated emission standard in a referencing subpart is more stringent than the standard that was proposed, the owner or operator of a new or reconstructed source subject to that standard for which construction or reconstruction is commenced between the proposal and promulgation dates of the standard shall comply with performance testing requirements within 180 days after the standard's effective date, or within 180 days after start-up of the source, whichever is later. If a promulgated standard in a referencing subpart is more stringent than the proposed standard, the owner or operator may choose to demonstrate compliance initially with either the proposed or the promulgated standard. If the owner or operator chooses to comply with the proposed standard initially, the owner or operator shall conduct a second performance test within 3 years and 180 days after the effective date of the standard, or after start-up of the source, whichever is later, to demonstrate compliance with the promulgated standard.

(2) The Administrator may require an owner or operator to conduct performance tests and compliance assessments at the regulated source at any time when the action is authorized by section 114 of the Act.

(3) Unless already permitted by the applicable title V permit, if an owner or operator elects to use a recovery device to replace an existing control device at a later date, or elects to use a different flare, nonflare control device or recovery device to replace an existing flare, nonflare control device or final recovery device at a later date, the owner or operator shall notify the Administrator, either by amendment of the regulated source's title V permit or, if title V is not applicable, by submission of the notice specified in §63.999(c)(7) before implementing the change. Upon implementing the change, a compliance demonstration or performance test shall be performed according to the provisions of paragraphs (c)(3)(i) through (v) of this section, as applicable, within 180 days. The compliance assessment report shall be submitted to the Administrator within 60 days of completing the determination, as provided in §63.999(a)(1)(ii).

(i) For flares used to replace an existing control device, a flare compliance demonstration shall be performed using the methods specified in §63.987(b);

(ii) For flares used to replace an existing final recovery device that is used on an applicable process vent, the owner or operator shall comply with the applicable provisions in a referencing subpart and in this subpart;

(iii) For incinerators, boilers, or process heaters used to replace an existing control device, a performance test shall be performed, using the methods specified in §63.997;

(iv) For absorbers, condensers, or carbon adsorbers used to replace an existing control device on a process vent or a transfer rack, a performance test shall be performed, using the methods specified in §63.997;

(v) For absorbers, condensers, or carbon adsorbers used to replace an existing final recovery device on a process vent, the owner or operator shall comply with the applicable provisions of a referencing subpart and this subpart;

(d) *Performance testing facilities.* If required to do performance testing, the owner or operator of each new regulated source and, at the request of the Administrator, the owner or operator of each existing regulated source, shall provide performance testing facilities as specified in paragraphs (d)(1) through (5) of this section.

(1) Sampling ports adequate for test methods applicable to such source. This includes, as applicable, the requirements specified in (d)(1)(i) and (ii) of this section.

(i) Constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures; and

(ii) Providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures;

(2) Safe sampling platform(s);

(3) Safe access to sampling platform(s);

(4) Utilities for sampling and testing equipment; and

(5) Any other facilities that the Administrator deems necessary for safe and adequate testing of a source.

(e) *Performance test procedures.* Where §§63.985 through 63.995 require the owner or operator to conduct a performance test of a control device or a halogen reduction device, the owner or operator shall follow the requirements of paragraphs (e)(1)(i) through (v) of this section, as applicable.

(1) *General procedures.* (i) *Continuous unit operations.* For continuous unit operations, performance tests shall be conducted at maximum representative operating conditions for the process, unless the Administrator specifies or approves alternate operating conditions. During the performance test, an owner or operator may operate the control or halogen reduction device at maximum or minimum representative operating conditions for monitored control or halogen reduction device parameters, whichever results in lower emission reduction. Operations during periods of start-up, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

(ii) [Reserved]

(iii) *Combination of both continuous and batch unit operations.* For a combination of both continuous and batch unit operations, performance tests shall be conducted at maximum representative operating conditions. For the purpose of conducting a performance test on a combined vent stream, maximum representative operating conditions shall be when batch emission episodes are occurring that result in the highest organic HAP emission rate (for the combined vent stream) that is achievable during the 6-month period that begins 3 months before and ends 3 months after the compliance assessment (e.g. TRE calculation, performance test) without causing any of the situations described in paragraphs (e)(1)(iii)(A) through (C) of this section.

(A) Causing damage to equipment;

(B) Necessitating that the owner or operator make product that does not meet an existing specification for sale to a customer; or

(C) Necessitating that the owner or operator make product in excess of demand.

(iv) *Alternatives to performance test requirements.* Performance tests shall be conducted and data shall be reduced in accordance with the test methods and procedures set forth in this subpart, in each relevant standard, and, if required, in applicable appendices of 40 CFR parts 51,

60, 61, and 63 unless the Administrator specifies one of the provisions in paragraphs (e)(1)(iv)(A) through (E) of this section.

(A) Specifies or approves, in specific cases, the use of a test method with minor changes in methodology; or

(B) Approves the use of an alternative test method, the results of which the Administrator has determined to be adequate for indicating whether a specific regulated source is in compliance. The alternate method or data shall be validated using the applicable procedures of Method 301 of appendix A of 40 CFR part 63; or

(C) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors; or

(D) Waives the requirement for the performance test as specified in paragraph (b)(2) of this section because the owner or operator of a regulated source has demonstrated by other means to the Administrator's satisfaction that the regulated source is in compliance with the relevant standard; or

(E) Approves the use of an equivalent method.

(v) *Performance test runs.* Except as provided in paragraphs (e)(1)(v)(A) and (B) of this section, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for at least 1 hour and under the conditions specified in this section. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(A) For control devices used to control emissions from transfer racks (except low throughput transfer racks that are capable of continuous vapor processing but do not handle continuous emissions or multiple loading arms of a transfer rack that load simultaneously), each run shall represent at least one complete tank truck or tank car loading period, during which regulated materials are loaded, and samples shall be collected using integrated sampling or grab samples taken at least four times per hour at approximately equal intervals of time, such as 15-minute intervals.

(B) For intermittent vapor processing systems used for controlling transfer rack emissions (except low throughput transfer racks that do not handle continuous emissions or multiple loading arms of a transfer rack that load simultaneously), each run shall represent at least one complete control device cycle, and samples shall be collected using integrated sampling or grab samples taken at least four times per hour at approximately equal intervals of time, such as 15-minute intervals.

(2) *Specific procedures.* Where §§63.985 through 63.995 require the owner or operator to conduct a performance test of a control device, or a halogen reduction device, an owner or operator shall conduct that performance test using the procedures in paragraphs (e)(2)(i) through (iv) of this section, as applicable. The regulated material concentration and percent reduction may be measured as either total organic regulated material or as TOC minus methane and ethane according to the procedures specified.

(i) *Selection of sampling sites.* Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites.

(A) For determination of compliance with a percent reduction requirement of total organic regulated material or TOC, sampling sites shall be located as specified in paragraphs (e)(2)(i)(A)(1) and (e)(2)(i)(A)(2) of this section, and at the outlet of the control device.

(1) With the exceptions noted below in paragraphs (e)(2)(i)(A)(2) and (3), the control device inlet sampling site shall be located at the exit from the unit operation before any control device.

(2) For process vents from continuous unit operations at affected sources in subcategories where the applicability criteria includes a TRE index value, the control device inlet sampling site shall be located after the final recovery device.

(3) If a vent stream is introduced with the combustion air or as a secondary fuel into a boiler or process heater with a design capacity less than 44 megawatts, selection of the location of the inlet sampling sites shall ensure the measurement of total organic regulated material or TOC (minus methane and ethane) concentrations, as applicable, in all vent streams and primary and secondary fuels introduced into the boiler or process heater.

(B) For determination of compliance with a parts per million by volume total regulated material or TOC limit in a referencing subpart, the sampling site shall be located at the outlet of the control device.

(ii) *Gas volumetric flow rate.* The gas volumetric flow rate shall be determined using Method 2, 2A, 2C, 2D, 2F, or 2G of 40 CFR part 60, appendix A, as appropriate.

(iii) *Total organic regulated material or TOC concentration.* To determine compliance with a parts per million by volume total organic regulated material or TOC limit, the owner or operator shall use Method 18 or 25A of 40 CFR part 60, appendix A, as applicable. The ASTM D6420-99 may be used in lieu of Method 18 of 40 CFR part 60, appendix A, under the conditions specified in paragraphs (e)(2)(iii)(D)(1) through (3) of this section. Alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of 40 CFR part 63 may be used. The procedures specified in paragraphs (e)(2)(iii)(A), (B), (D), and (E) of this section shall be used to calculate parts per million by volume concentration. The calculated concentration shall be corrected to 3 percent oxygen using the procedures specified in paragraph (e)(2)(iii)(C) of this section if a combustion device is the control device and supplemental combustion air is used to combust the emissions.

(A) *Sampling time.* For continuous unit operations and for a combination of both continuous and batch unit operations, the minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15 minute intervals during the run.

(B) *Concentration calculation.* The concentration of either TOC (minus methane or ethane) or total organic regulated material shall be calculated according to paragraph (e)(2)(iii)(B) (1) or (2) of this section.

(1) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using Equation 2.

$$C_{\text{TOC}} = \sum_{i=1}^x \left(\frac{\sum_{j=1}^n C_{ji}}{x} \right) \quad [\text{Eq. 2}]$$

[View or download PDF](#)

Where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

x = Number of samples in the sample run.

n = Number of components in the sample.

C_{ji} = Concentration of sample components j of sample I, dry basis, parts per million by volume.

(2) The total organic regulated material (C_{REG}) shall be computed according to Equation 2 in paragraph (e)(2)(iii)(B)(1) of this section except that only the regulated species shall be summed.

(C) *Concentration correction calculation.* The concentration of TOC or total organic regulated material, as applicable, shall be corrected to 3 percent oxygen if a combustion device is the control device and supplemental combustion air is used to combust the emissions.

(1) The emission rate correction factor (or excess air), integrated sampling and analysis procedures of Method 3B of 40 CFR part 60, appendix A, or American Society of Mechanical Engineers (ASME) PTC 19-10-1981-Part 10 (available for purchase from: ASME International, Three Park Avenue, New York, NY 10016-5990, 800-843-2763 or 212-591-7722), shall be used to determine the oxygen concentration. The sampling site shall be the same as that of the organic regulated material or organic compound samples, and the samples shall be taken during the same time that the organic regulated material or organic compound samples are taken.

(2) The concentration corrected to 3 percent oxygen (C_c) shall be computed using Equation 3.

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right) \quad [Eq. 3]$$

[View or download PDF](#)

Where:

C_c = Concentration of TOC or organic regulated material corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = Concentration of TOC (minus methane and ethane) or organic regulated material, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percentage by volume.

(D) To measure the total organic regulated material concentration at the outlet of a control device, use Method 18 of 40 CFR part 60, appendix A, or ASTM D6420-99. If you have a combustion control device, you must first determine which regulated material compounds are present in the inlet gas stream using process knowledge or the screening procedure described in Method 18. In conducting the performance test, analyze samples collected at the outlet of the combustion control device as specified in Method 18 or ASTM D6420-99 for the regulated material compounds present at the inlet of the control device. The method ASTM D6420-99 may be used only under the conditions specified in paragraphs (e)(2)(iii)(D)(1) through (3) of this section.

(1) If the target compound(s) is listed in Section 1.1 of ASTM D6420-99 and the target concentration is between 150 parts per billion by volume and 100 parts per million by volume.

(2) If the target compound(s) is not listed in Section 1.1 of ASTM D6420-99 but is potentially detected by mass spectrometry, an additional system continuing calibration check after each run, as detailed in Section 10.5.3 of ASTM D6420-99, must be followed, met, documented, and submitted with the performance test report even if you do not use a moisture condenser or the compound is not considered soluble.

(3) If a minimum of one sample/analysis cycle is completed at least every 15 minutes.

(E) To measure the TOC concentration, use Method 18 of 40 CFR part 60, appendix A, or use Method 25A of 40 CFR part 60, appendix A, according to the procedures in paragraphs (e)(2)(iii)(E)(1) through (4) of this section.

(1) Calibrate the instrument on the predominant regulated material compound.

(2) The test results are acceptable if the response from the high level calibration gas is at least 20 times the standard deviation for the response from the zero calibration gas when the instrument is zeroed on its most sensitive scale.

(3) The span value of the analyzer must be less than 100 parts per million by volume.

(4) Report the results as carbon, calculated according to Equation 25A-1 of Method 25A of 40 CFR part 60, appendix A.

(iv) *Percent reduction calculation.* To determine compliance with a percent reduction requirement, the owner or operator shall use Method 18, 25, or 25A of 40 CFR part 60, appendix A, as applicable. The method ASTM D6420-99 may be used in lieu of Method 18 of 40 CFR part 60, appendix A, under the conditions specified in paragraphs (e)(2)(iii)(D)(1) through (3) of this section. Alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of 40 CFR part 63 may be used. The procedures specified in paragraphs (e)(2)(iv)(A) through (I) of this section shall be used to calculate percent reduction efficiency.

(A) *Sampling time.* The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) *Mass rate of TOC or total organic regulated material.* The mass rate of either TOC (minus methane and ethane) or total organic regulated material (E_i , E_o) shall be computed as applicable.

(1) Equations 4 and 5 shall be used.

$$E_i = K_2 \left(\sum_{j=1}^n C_{ij} M_{ij} \right) Q_i \quad [Eq. 4]$$

[View or download PDF](#)

$$E_o = K_2 \left(\sum_{j=1}^n C_{oj} M_{oj} \right) Q_o \quad [Eq. 5]$$

[View or download PDF](#)

Where:

E_i , E_o = Emission rate of TOC (minus methane and ethane) (E_{TOC}) or emission rate of total organic regulated material (E_{RM}) in the sample at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million)⁻¹ (gram-mole per standard cubic meter) (kilogram per gram) (minute per hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

n = Number of components in the sample.

C_{ij} , C_{oj} = Concentration on a dry basis of organic compound j in parts per million by volume of the gas stream at the inlet and outlet of the control device, respectively. If the TOC emission rate is being calculated, C_{ij} and C_{oj} include all organic compounds measured minus methane and ethane; if the total organic regulated material emissions rate is being calculated, only organic regulated material are included.

M_{ij} , M_{oj} = Molecular weight of organic compound j , gram per gram-mole, of the gas stream at the inlet and outlet of the control device, respectively.

Q_i , Q_o = Process vent flow rate, dry standard cubic meter per minute, at a temperature of 20 °C, at the inlet and outlet of the control device, respectively.

(2)-(3) [Reserved]

(C) *Percent reduction in TOC or total organic regulated material for continuous unit operations and a combination of both continuous and batch unit operations.* For continuous unit operations and for a combination of both continuous and batch unit operations, the percent reduction in TOC (minus methane and ethane) or total organic regulated material shall be calculated using Equation 6.

$$R = \frac{E_i - E_o}{E_i} (100) \quad [Eq. 6]$$

[View or download PDF](#)

Where:

R = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) or total organic regulated material at the inlet to the control device as calculated under paragraph (e)(2)(iv)(B) of this section, kilograms TOC per hour or kilograms organic regulated material per hour.

E_o = Mass rate of TOC (minus methane and ethane) or total organic regulated material at the outlet of the control device, as calculated under paragraph (e)(2)(iv)(B) of this section, kilograms TOC per hour or kilograms total organic regulated material per hour.

(D) *Vent stream introduced with combustion air or as secondary fuel.* 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, the weight-percent reduction of total organic regulated

material or TOC (minus methane and ethane) across the device shall be determined by comparing the TOC (minus methane and ethane) or total organic regulated material in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) or total organic regulated material exiting the combustion device, respectively.

(E) *Transfer racks.* Method 25A of 40 CFR part 60, appendix A, may also be used for the purpose of determining compliance with the percent reduction requirement for transfer racks.

(1) If Method 25A of 40 CFR part 60, appendix A, is used to measure the concentration of organic compounds (C_{TOC}), the principal organic regulated material in the vent stream shall be used as the calibration gas.

(2) An emission testing interval shall consist of each 15-minute period during the performance test. For each interval, a reading from each measurement shall be recorded.

(3) The average organic compound concentration and the volume measurement shall correspond to the same emissions testing interval.

(4) The mass at the inlet and outlet of the control device during each testing interval shall be calculated using Equation 7.

$$M_j = FKV_s C_t \quad [\text{Eq. 7}]$$

[View or download PDF](#)

Where:

M_j = Mass of organic compounds emitted during testing interval j , kilograms.

$F = 10^{-6}$ = Conversion factor, (cubic meters regulated material per cubic meters air) * (parts per million by volume) $^{-1}$.

K = Density, kilograms per standard cubic meter organic regulated material.

= 659 kilograms per standard cubic meter organic regulated material. (Note: The density term cancels out when the percent reduction is calculated. Therefore, the density used has no effect. The density of hexane is given so that it can be used to maintain the units of M_j .)

V_s = Volume of air-vapor mixture exhausted at standard conditions, 20 °C and 760 millimeters mercury, standard cubic meters.

C_t = Total concentration of organic compounds (as measured) at the exhaust vent, parts per million by volume, dry basis.

(5) The organic compound mass emission rates at the inlet and outlet of the control device shall be calculated using Equations 8 and 9 as follows:

$$E_i = \frac{\sum_{j=1}^n M_{ij}}{T} \quad [Eq. 8]$$

[View or download PDF](#)

$$E_o = \frac{\sum_{j=1}^n M_{oj}}{T} \quad [Eq. 9]$$

[View or download PDF](#)

Where:

E_i , E_o = Mass flow rate of organic compounds at the inlet (i) and outlet (o) of the control device, kilograms per hour.

n = Number of testing intervals.

M_{ij} , M_{oj} = Mass of organic compounds at the inlet (i) or outlet (o) during testing interval j , kilograms.

T = Total time of all testing intervals, hours.

(F) To measure inlet and outlet concentrations of total organic regulated material, use Method 18 of 40 CFR part 60, appendix A, or ASTM D6420-99, under the conditions specified in paragraphs (e)(2)(iii)(D)(1) through (3) of this section. In conducting the performance test, collect and analyze samples as specified in Method 18 or ASTM D6420-99. You must collect samples simultaneously at the inlet and outlet of the control device. If the performance test is for a combustion control device, you must first determine which regulated material compounds are present in the inlet gas stream (i.e., uncontrolled emissions) using process knowledge or the screening procedure described in Method 18. Quantify the emissions for the regulated material compounds present in the inlet gas stream for both the inlet and outlet gas streams for the combustion device.

(G) To determine inlet and outlet concentrations of TOC, use Method 25 of 40 CFR part 60, appendix A. Measure the total gaseous non-methane organic (TGNMO) concentration of the inlet and outlet vent streams using the procedures of Method 25. Use the TGNMO concentration in Equations 4 and 5 of paragraph (e)(2)(iv)(B) of this section.

(H) Method 25A of 40 CFR part 60, appendix A, may be used instead of Method 25 to measure inlet and outlet concentrations of TOC if the condition in either paragraph (e)(2)(iv)(H)(1) or (2) of this section is met.

(1) The concentration at the inlet to the control system and the required level of control would result in exhaust TGNMO concentrations of 50 parts per million by volume or less.

(2) Because of the high efficiency of the control device, the anticipated TGNMO concentration of the control device exhaust is 50 parts per million by volume or less, regardless of the inlet concentration.

(I) If the uncontrolled or inlet gas stream to the control device contains formaldehyde, you must conduct emissions testing according to paragraph (e)(2)(iv)(I)(1) or (2) of this section.

(1) If you elect to comply with a percent reduction requirement and formaldehyde is the principal regulated material compound (i.e., greater than 50 percent of the regulated material compounds in the stream by volume), you must use Method 316 or 320 of 40 CFR part 63, appendix A, to measure formaldehyde at the inlet and outlet of the control device. Use the percent reduction in formaldehyde as a surrogate for the percent reduction in total regulated material emissions.

(2) If you elect to comply with an outlet total organic regulated material concentration or TOC concentration limit, and the uncontrolled or inlet gas stream to the control device contains greater than 10 percent (by volume) formaldehyde, you must use Method 316 or 320 of 40 CFR part 63, appendix A, to separately determine the formaldehyde concentration. Calculate the total organic regulated material concentration or TOC concentration by totaling the formaldehyde emissions measured using Method 316 or 320 and the other regulated material compound emissions measured using Method 18 or 25/25A.

(3) An owner or operator using a halogen scrubber or other halogen reduction device to control process vent and transfer rack halogenated vent streams in compliance with a referencing subpart, who is required to conduct a performance test to determine compliance with a control efficiency or emission limit for hydrogen halides and halogens, shall follow the procedures specified in paragraphs (e)(3) (i) through (iv) of this section.

(i) For an owner or operator determining compliance with the percent reduction of total hydrogen halides and halogens, sampling sites shall be located at the inlet and outlet of the scrubber or other halogen reduction device used to reduce halogen emissions. For an owner or operator determining compliance with a kilogram per hour outlet emission limit for total hydrogen halides and halogens, the sampling site shall be located at the outlet of the scrubber or other halogen reduction device and prior to any releases to the atmosphere.

(ii) Except as provided in paragraph (e)(1)(iv) of this section, Method 26 or Method 26A of 40 CFR part 60, appendix A, shall be used to determine the concentration, in milligrams per dry standard cubic meter, of total hydrogen halides and halogens that may be present in the vent stream. The mass emissions of each hydrogen halide and halogen compound shall be calculated from the measured concentrations and the gas stream flow rate.

(iii) To determine compliance with the percent removal efficiency, the mass emissions for any hydrogen halides and halogens present at the inlet of the halogen reduction device shall be summed together. The mass emissions of the compounds present at the outlet of the scrubber or

other halogen reduction device shall be summed together. Percent reduction shall be determined by comparison of the summed inlet and outlet measurements.

(iv) To demonstrate compliance with a kilogram per hour outlet emission limit, the test results must show that the mass emission rate of total hydrogen halides and halogens measured at the outlet of the scrubber or other halogen reduction device is below the kilogram per hour outlet emission limit specified in a referencing subpart.

[64 FR 34866, June 29, 1999, as amended at 67 FR 46277, July 12, 2002]

[↑ Back to Top](#)

§63.998 Recordkeeping requirements.

(a) *Compliance assessment, monitoring, and compliance records*—(1) *Conditions of flare compliance assessment, monitoring, and compliance records.* Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of flare compliance assessments performed pursuant to §63.987(b).

(i) *Flare compliance assessment records.* When using a flare to comply with this subpart, record the information specified in paragraphs (a)(1)(i)(A) through (C) of this section for each flare compliance assessment performed pursuant to §63.987(b). As specified in §63.999(a)(2)(iii)(A), the owner or operator shall include this information in the flare compliance assessment report.

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted);

(B) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the flare compliance assessment; and

(C) All periods during the flare compliance assessment when all pilot flames are absent or, if only the flare flame is monitored, all periods when the flare flame is absent.

(ii) *Monitoring records.* Each owner or operator shall keep up to date and readily accessible hourly records of whether the monitor is continuously operating and whether the flare flame or at least one pilot flame is continuously present. For transfer racks, hourly records are required only while the transfer rack vent stream is being vented.

(iii) *Compliance records.* (A) Each owner or operator shall keep records of the times and duration of all periods during which the flare flame or all the pilot flames are absent. This record shall be submitted in the periodic reports as specified in §63.999(c)(3).

(B) Each owner or operator shall keep records of the times and durations of all periods during which the monitor is not operating.

(2) *Nonflare control device performance test records.* (i) *Availability of performance test records.* Upon request, the owner or operator shall make available to the Administrator such

records as may be necessary to determine the conditions of performance tests performed pursuant to §63.988(b), §63.990(b), §63.994(b), or §63.995(b).

(ii) Nonflare control device and halogen reduction device performance test records.

(A) *General requirements.* Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the data specified in paragraphs (a)(2)(ii)(B) through (C) of this section, as applicable, measured during each performance test performed pursuant to §63.988(b), §63.990(b), §63.994(b), or §63.995(b), and also include that data in the Notification of Compliance Status required under §63.999(b). The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a combustion device, or the outlet concentration of TOC or regulated material is determined.

(B) *Nonflare combustion device.* Where an owner or operator subject to the provisions of this paragraph seeks to demonstrate compliance with a percent reduction requirement or a parts per million by volume requirement using a nonflare combustion device the information specified in (a)(2)(ii)(B)(1) through (6) of this section shall be recorded.

(1) For thermal incinerators, record the fire box temperature averaged over the full period of the performance test.

(2) For catalytic incinerators, record the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test.

(3) For a boiler or process heater with a design heat input capacity less than 44 megawatts and a vent stream that is not introduced with or as the primary fuel, record the fire box temperature averaged over the full period of the performance test.

(4) For an incinerator, record the percent reduction of organic regulated material, if applicable, or TOC achieved by the incinerator determined as specified in §63.997(e)(2)(iv), as applicable, or the concentration of organic regulated material (parts per million by volume, by compound) determined as specified in §63.997(e)(2)(iii) at the outlet of the incinerator.

(5) For a boiler or process heater, record a description of the location at which the vent stream is introduced into the boiler or process heater.

(6) For a boiler or process heater with a design heat input capacity of less than 44 megawatts and where the process vent stream is introduced with combustion air or used as a secondary fuel and is not mixed with the primary fuel, record the percent reduction of organic regulated material or TOC, or the concentration of regulated material or TOC (parts per million by volume, by compound) determined as specified in §63.997(e)(2)(iii) at the outlet of the combustion device.

(C) *Other nonflare control devices.* Where an owner or operator seeks to use an absorber, condenser, or carbon adsorber as a control device, the information specified in paragraphs (a)(2)(ii)(C)(1) through (5) of this section shall be recorded, as applicable.

(1) Where an absorber is used as the control device, the exit specific gravity and average exit temperature of the absorbing liquid averaged over the same time period as the performance test (both measured while the vent stream is normally routed and constituted); or

(2) Where a condenser is used as the control device, the average exit (product side) temperature averaged over the same time period as the performance test while the vent stream is routed and constituted normally; or

(3) Where a carbon adsorber is used as the control device, the total regeneration stream mass flow during each carbon-bed regeneration cycle during the period of the performance test, and temperature of the carbon-bed after each regeneration during the period of the performance test (and within 15 minutes of completion of any cooling cycle or cycles; or

(4) As an alternative to paragraph (a)(2)(ii)(C)(1), (2), or (3) of this section, the concentration level or reading indicated by an organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber averaged over the same time period as the performance test while the vent stream is normally routed and constituted.

(5) For an absorber, condenser, or carbon adsorber used as a control device, the percent reduction of regulated material achieved by the control device or concentration of regulated material (parts per million by volume, by compound) at the outlet of the control device.

(D) *Halogen reduction devices.* When using a scrubber following a combustion device to control a halogenated vent stream, record the information specified in paragraphs (a)(2)(ii)(D)(1) through (3) of this section.

(1) The percent reduction or scrubber outlet mass emission rate of total hydrogen halides and halogens as specified in §63.997(e)(3).

(2) The pH of the scrubber effluent averaged over the time period of the performance test; and

(3) The scrubber liquid-to-gas ratio averaged over the time period of the performance test.

(3) *Recovery device monitoring records during TRE index value determination.* For process vents that require control of emissions under a referencing subpart, owners or operators using a recovery device to maintain a TRE above a level specified in the referencing subpart shall maintain the continuous records specified in paragraph (a)(3)(i) through (v) of this section, as applicable, and submit reports as specified in §63.999(a)(2)(iii)(C).

(i) Where an absorber is the final recovery device in the recovery system and the saturated scrubbing fluid and specific gravity of the scrubbing fluid is greater than or equal to 0.02 specific gravity units, the exit specific gravity (or alternative parameter that is a measure of the degree of

absorbing liquid saturation if approved by the Administrator) and average exit temperature of the absorbing liquid averaged over the same time period as the TRE index value determination (both measured while the vent stream is normally routed and constituted); or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature averaged over the same time period as the TRE index value determination while the vent stream is routed and constituted normally; or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total regeneration stream mass flow during each carbon-bed regeneration cycle during the period of the TRE index value determination, and temperature of the carbon-bed after each regeneration during the period of the TRE index value determination (and within 15 minutes of completion of any cooling cycle or cycles); or

(iv) As an alternative to paragraph (a)(3)(i), (ii), or (iii) of this section, the concentration level or reading indicated by an organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber averaged over the same time period as the TRE index value determination while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream as specified in a referencing subpart.

(4) *Halogen concentration records.* Record the halogen concentration in the vent stream determined according to the procedures specified in a referencing subpart. Submit this record in the Notification of Compliance Status, as specified in §63.999(b)(4). If the owner or operator designates the vent stream as halogenated, then this shall be recorded and reported in the Notification of Compliance Status report.

(b) *Continuous records and monitoring system data handling*—(1) *Continuous records.* Where this subpart requires a continuous record, the owner or operator shall maintain a record as specified in paragraphs (b)(1)(i) through (iv) of this section, as applicable:

(i) A record of values measured at least once every 15 minutes or each measured value for systems which measure more frequently than once every 15 minutes; or

(ii) A record of block average values for 15-minute or shorter periods calculated from all measured data values during each period or from at least one measured data value per minute if measured more frequently than once per minute.

(iii) Where data is collected from an automated continuous parameter monitoring system, the owner or operator may calculate and retain block hourly average values from each 15-minute block average period or from at least one measured value per minute if measured more frequently than once per minute, and discard all but the most recent three valid hours of continuous (15-minute or shorter) records, if the hourly averages do not exclude periods of CPMS breakdown or malfunction. An automated CPMS records the measured data and calculates the hourly averages through the use of a computerized data acquisition system.

(iv) A record as required by an alternative approved under a referencing subpart.

(2) *Excluded data.* Monitoring data recorded during periods identified in paragraphs (b)(2)(i) through (iii) of this section shall not be included in any average computed to determine compliance with an emission limit in a referencing subpart.

(i) Monitoring system breakdowns, repairs, preventive maintenance, calibration checks, and zero (low-level) and high-level adjustments;

(ii) Periods of non-operation of the process unit (or portion thereof), resulting in cessation of the emissions to which the monitoring applies; and

(iii) Startups, shutdowns, and malfunctions, if the owner or operator operates the source during such periods in accordance with §63.1111(a) and maintains the records specified in paragraph (d)(3) of this section.

(3) *Records of daily averages.* In addition to the records specified in paragraph (a), owners or operators shall keep records as specified in paragraphs (b)(3)(i) and (ii) of this section and submit reports as specified in §63.999(c), unless an alternative recordkeeping system has been requested and approved under a referencing subpart.

(i) Except as specified in paragraph (b)(3)(ii) of this section, daily average values of each continuously monitored parameter shall be calculated from data meeting the specifications of paragraph (b)(2) of this section for each operating day and retained for 5 years.

(A) The daily average shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the period of operation per operating day if operation is not continuous (e.g., for transfer racks the average shall cover periods of loading). If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the daily average instead of all measured values.

(B) The operating day shall be the period defined in the operating permit or in the Notification of Compliance Status. It may be from midnight to midnight or another daily period.

(ii) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status or in the operating permit, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that operating day. In such cases, the owner or operator may not discard the recorded values as allowed in paragraph (b)(1)(iii) of this section.

(4) [Reserved]

(5) *Alternative recordkeeping.* For any parameter with respect to any item of equipment associated with a process vent or transfer rack (except low throughput transfer loading racks), the owner or operator may implement the recordkeeping requirements in paragraphs (b)(5)(i) or (ii)

of this section as alternatives to the recordkeeping provisions listed in paragraphs (b)(1) through (3) of this section. The owner or operator shall retain each record required by paragraphs (b)(5)(i) or (ii) of this section as provided in a referencing subpart.

(i) The owner or operator may retain only the daily average value, and is not required to retain more frequently monitored operating parameter values, for a monitored parameter with respect to an item of equipment, if the requirements of paragraphs (b)(5)(i)(A) through (F) of this section are met. The owner or operator shall notify the Administrator in the Notification of Compliance Status as specified in §63.999(b)(5) or, if the Notification of Compliance Status has already been submitted, in the Periodic Report immediately preceding implementation of the requirements of this paragraph, as specified in §63.999(c)(6)(iv).

(A) The monitoring system is capable of detecting unrealistic or impossible data during periods of operation other than start-ups, shutdowns or malfunctions (e.g., a temperature reading of -200°C on a boiler), and will alert the operator by alarm or other means. The owner or operator shall record the occurrence. All instances of the alarm or other alert in an operating day constitute a single occurrence.

(B) The monitoring system generates a running average of the monitoring values, updated at least hourly throughout each operating day, that have been obtained during that operating day, and the capability to observe this average is readily available to the Administrator on-site during the operating day. The owner or operator shall record the occurrence of any period meeting the criteria in paragraphs (b)(5)(i)(B)(1) through (3) of this section. All instances in an operating day constitute a single occurrence.

(1) The running average is above the maximum or below the minimum established limits;

(2) The running average is based on at least six one-hour average values; and

(3) The running average reflects a period of operation other than a start-up, shutdown, or malfunction.

(C) The monitoring system is capable of detecting unchanging data during periods of operation other than start-ups, shutdowns or malfunctions, except in circumstances where the presence of unchanging data is the expected operating condition based on past experience (e.g., pH in some scrubbers), and will alert the operator by alarm or other means. The owner or operator shall record the occurrence. All instances of the alarm or other alert in an operating day constitute a single occurrence.

(D) The monitoring system will alert the owner or operator by an alarm, if the running average parameter value calculated under paragraph (b)(5)(i)(B) of this section reaches a set point that is appropriately related to the established limit for the parameter that is being monitored.

(E) The owner or operator shall verify the proper functioning of the monitoring system, including its ability to comply with the requirements of paragraph (b)(5)(i) of this section, at the

times specified in paragraphs (b)(5)(i)(E)(1) through (3) of this section. The owner or operator shall document that the required verifications occurred.

(1) Upon initial installation.

(2) Annually after initial installation.

(3) After any change to the programming or equipment constituting the monitoring system that might reasonably be expected to alter the monitoring system's ability to comply with the requirements of this section.

(F) The owner or operator shall retain the records identified in paragraphs (b)(5)(i)(F)(1) through (4) of this section.

(1) Identification of each parameter, for each item of equipment, for which the owner or operator has elected to comply with the requirements of paragraph (b)(5)(i) of this section.

(2) A description of the applicable monitoring system(s), and of how compliance will be achieved with each requirement of paragraph (b)(5)(i)(A) through (E) of this section. The description shall identify the location and format (e.g., on-line storage; log entries) for each required record. If the description changes, the owner or operator shall retain both the current and the most recent superseded description. The description, and the most recent superseded description, shall be retained as provided in the subpart that references this subpart, except as provided in paragraph (b)(5)(i)(F)(1) of this section.

(3) A description, and the date, of any change to the monitoring system that would reasonably be expected to affect its ability to comply with the requirements of paragraph (b)(5)(i) of this section.

(4) Owners and operators subject to paragraph (b)(5)(i)(F)(2) of this section shall retain the current description of the monitoring system as long as the description is current, but not less than 5 years from the date of its creation. The current description shall be retained on-site at all times or be accessible from a central location by computer or other means that provides access within 2 hours after a request. The owner or operator shall retain the most recent superseded description at least until 5 years from the date of its creation. The superseded description shall be retained on-site (or accessible from a central location by computer that provides access within 2 hours after a request) at least 6 months after being superseded. Thereafter, the superseded description may be stored off-site.

(ii) If an owner or operator has elected to implement the requirements of paragraph (b)(5)(i) of this section, and a period of 6 consecutive months has passed without an excursion as defined in paragraph (b)(6)(i) of this section, the owner or operator is no longer required to record the daily average value for that parameter for that unit of equipment, for any operating day when the daily average value is less than the maximum, or greater than the minimum established limit. With approval by the Administrator, monitoring data generated prior to the compliance date of this

subpart shall be credited toward the period of 6 consecutive months, if the parameter limit and the monitoring were required and/or approved by the Administrator.

(A) If the owner or operator elects not to retain the daily average values, the owner or operator shall notify the Administrator in the next Periodic Report, as specified in §63.999(c)(6)(i). The notification shall identify the parameter and unit of equipment.

(B) If there is an excursion as defined in paragraph (b)(6)(i) of this section on any operating day after the owner or operator has ceased recording daily averages as provided in paragraph (b)(5)(ii) of this section, the owner or operator shall immediately resume retaining the daily average value for each operating day, and shall notify the Administrator in the next Periodic Report, as specified in §63.999(c). The owner or operator shall continue to retain each daily average value until another period of 6 consecutive months has passed without an excursion as defined in paragraph (b)(6)(i) of this section.

(C) The owner or operator shall retain the records specified in paragraphs (b)(5)(i)(A) through (F) of this section for the duration specified in a referencing subpart. For any week, if compliance with paragraphs (b)(5)(i)(A) through (D) of this section does not result in retention of a record of at least one occurrence or measured parameter value, the owner or operator shall record and retain at least one parameter value during a period of operation other than a start-up, shutdown, or malfunction.

(6)(i) For the purposes of this section, an excursion means that the daily average value of monitoring data for a parameter is greater than the maximum, or less than the minimum established value, except as provided in paragraphs (b)(6)(i)(A) and (B) of this section.

(A) The daily average value during any startup, shutdown, or malfunction shall not be considered an excursion if the owner or operator operates the source during such periods in accordance with §63.1111(a) and maintains the records specified in paragraph (d)(3) of this section.

(B) An excused excursion, as described in paragraph (b)(6)(ii), does not count toward the number of excursions for the purposes of this subpart.

(ii) One excused excursion for each control device or recovery device for each semiannual period is allowed. If a source has developed a startup, shutdown and malfunction plan, and a monitored parameter is outside its established range or monitoring data are not collected during periods of start-up, shutdown, or malfunction (and the source is operated during such periods in accordance with §63.1111(a)) or during periods of nonoperation of the process unit or portion thereof (resulting in cessation of the emissions to which monitoring applies), then the excursion is not a violation and, in cases where continuous monitoring is required, the excursion does not count as the excused excursion for determining compliance.

(c) *Nonflare control and recovery device regulated source monitoring records*—(1) *Monitoring system records*. For process vents and high throughput transfer racks, the owner or operator subject to this subpart shall keep the records specified in this paragraph, as well as records specified elsewhere in this subpart.

(i) For a CPMS used to comply with this part, a record of the procedure used for calibrating the CPMS.

(ii) For a CPMS used to comply with this subpart, records of the information specified in paragraphs (c)(ii)(A) through (H) of this section, as indicated in a referencing subpart.

(A) The date and time of completion of calibration and preventive maintenance of the CPMS.

(B) The “as found” and “as left” CPMS readings, whenever an adjustment is made that affects the CPMS reading and a “no adjustment” statement otherwise.

(C) The start time and duration or start and stop times of any periods when the CPMS is inoperative.

(D) Records of the occurrence and duration of each start-up, shutdown, and malfunction of CPMS used to comply with this subpart during which excess emissions (as defined in a referencing subpart) occur.

(E) For each start-up, shutdown, and malfunction during which excess emissions as defined in a referencing subpart occur, records whether the procedures specified in the source's start-up, shutdown, and malfunction plan were followed, and documentation of actions taken that are not consistent with the plan. These records may take the form of a “checklist,” or other form of recordkeeping that confirms conformance with the start-up, shutdown, and malfunction plan for the event.

(F) Records documenting each start-up, shutdown, and malfunction event.

(G) Records of CPMS start-up, shutdown, and malfunction event that specify that there were no excess emissions during the event, as applicable.

(H) Records of the total duration of operating time.

(2) *Combustion control and halogen reduction device monitoring records.* (i) Each owner or operator using a combustion control or halogen reduction device to comply with this subpart shall keep the following records up-to-date and readily accessible, as applicable. Continuous records of the equipment operating parameters specified to be monitored under §§63.988(c) (incinerator, boiler, and process heater monitoring), 63.994(c) (halogen reduction device monitoring), and 63.995(c) (other combustion systems used as control device monitoring) or approved by the Administrator in accordance with a referencing subpart.

(ii) Each owner or operator shall keep records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in paragraph (b)(3)(i) of this section. For catalytic incinerators, record the daily average of the temperature upstream of the catalyst bed and the daily average of the temperature differential across the bed. For halogen scrubbers record the daily average pH and the liquid-to-gas ratio.

(iii) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible records of periods of operation during which the parameter boundaries are exceeded. The parameter boundaries are established pursuant to §63.996(c)(6).

(3) *Monitoring records for recovery devices, absorbers, condensers, carbon adsorbers or other noncombustion systems used as control devices.* (i) Each owner or operator using a recovery device to achieve and maintain a TRE index value greater than the control applicability level specified in the referencing subpart but less than 4.0 or using an absorber, condenser, carbon adsorber or other non-combustion system as a control device shall keep readily accessible, continuous records of the equipment operating parameters specified to be monitored under §§63.990(c) (absorber, condenser, and carbon adsorber monitoring), 63.993(c) (recovery device monitoring), or 63.995(c) (other noncombustion systems used as a control device monitoring) or as approved by the Administrator in accordance with a referencing subpart. For transfer racks, continuous records are required while the transfer vent stream is being vented.

(ii) Each owner or operator shall keep records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in paragraph (b)(3)(i) of this section. If carbon adsorber regeneration stream flow and carbon bed regeneration temperature are monitored, the records specified in paragraphs (c)(3)(ii)(A) and (B) of this section shall be kept instead of the daily averages.

(A) Records of total regeneration stream mass or volumetric flow for each carbon-bed regeneration cycle.

(B) Records of the temperature of the carbon bed after each regeneration and within 15 minutes of completing any cooling cycle.

(iii) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible records of periods of operation during which the parameter boundaries are exceeded. The parameter boundaries are established pursuant to §63.996(c)(6).

(d) *Other records—(1) Closed vent system records.* For closed vent systems the owner or operator shall record the information specified in paragraphs (d)(1)(i) through (iv) of this section, as applicable.

(i) For closed vent systems collecting regulated material from a regulated source, the owner or operator shall record the identification of all parts of the closed vent system, that are designated as unsafe or difficult to inspect, an explanation of why the equipment is unsafe or difficult to inspect, and the plan for inspecting the equipment required by §63.983(b)(2)(ii) or (iii) of this section.

(ii) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall keep a record of the information specified in either paragraph (d)(1)(ii)(A) or (B) of this section, as applicable.

(A) Hourly records of whether the flow indicator specified under §63.983(a)(3)(i) was operating and whether a diversion was detected at any time during the hour, as well as records of the times of all periods when the vent stream is diverted from the control device or the flow indicator is not operating.

(B) Where a seal mechanism is used to comply with §63.983(a)(3)(ii), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanisms has been done, and shall record the occurrence of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has been broken.

(iii) For a closed vent system collecting regulated material from a regulated source, when a leak is detected as specified in §63.983(d)(2), the information specified in paragraphs (d)(1)(iii)(A) through (F) of this section shall be recorded and kept for 5 years.

(A) The instrument and the equipment identification number and the operator name, initials, or identification number.

(B) The date the leak was detected and the date of the first attempt to repair the leak.

(C) The date of successful repair of the leak.

(D) The maximum instrument reading measured by the procedures in §63.983(c) after the leak is successfully repaired or determined to be nonreparable.

(E) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 days after discovery of the leak. The owner or operator may develop a written procedure that identifies the conditions that justify a delay of repair. In such cases, reasons for delay of repair may be documented by citing the relevant sections of the written procedure.

(F) Copies of the Periodic Reports as specified in §63.999(c), if records are not maintained on a computerized database capable of generating summary reports from the records.

(iv) For each instrumental or visual inspection conducted in accordance with §63.983(b)(1) for closed vent systems collecting regulated material from a regulated source during which no leaks are detected, the owner or operator shall record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(2) *Storage vessel and transfer rack records.* An owner or operator shall keep readily accessible records of the information specified in paragraphs (d)(2)(i) and (ii) of this section, as applicable.

(i) A record of the measured values of the parameters monitored in accordance with §63.985(c) or §63.987(c).

(ii) A record of the planned routine maintenance performed on the control system during which the control system does not meet the applicable specifications of §63.983(a), §63.985(a), or

§63.987(a), as applicable, due to the planned routine maintenance. Such a record shall include the information specified in paragraphs (d)(2)(ii)(A) through (C) of this section. This information shall be submitted in the Periodic Reports as specified in §63.999(c)(4).

(A) The first time of day and date the requirements of §63.983(a), §63.985(a), or §63.987(a), as applicable, were not met at the beginning of the planned routine maintenance, and

(B) The first time of day and date the requirements of §63.983(a), §63.985(a), or §63.987(a), as applicable, were met at the conclusion of the planned routine maintenance.

(C) A description of the type of maintenance performed.

(3) *Regulated source and control equipment start-up, shutdown and malfunction records.* (i)

Records of the occurrence and duration of each start-up, shutdown, and malfunction of operation of process equipment or of air pollution control equipment used to comply with this part during which excess emissions (as defined in a referencing subpart) occur.

(ii) For each start-up, shutdown, and malfunction during which excess emissions occur, records that the procedures specified in the source's start-up, shutdown, and malfunction plan were followed, and documentation of actions taken that are not consistent with the plan. For example, if a start-up, shutdown, and malfunction plan includes procedures for routing control device emissions to a backup control device (e.g., the incinerator for a halogenated stream could be routed to a flare during periods when the primary control device is out of service), records must be kept of whether the plan was followed. These records may take the form of a "checklist," or other form of recordkeeping that confirms conformance with the start-up, shutdown, and malfunction plan for the event.

(4) *Equipment leak records.* The owner or operator shall maintain records of the information specified in paragraphs (d)(4)(i) and (ii) of this section for closed vent systems and control devices if specified by the equipment leak provisions in a referencing subpart. The records specified in paragraph (d)(4)(i) of this section shall be retained for the life of the equipment. The records specified in paragraph (d)(4)(ii) of this section shall be retained for 5 years.

(i) The design specifications and performance demonstrations specified in paragraphs (d)(4)(i)(A) through (C) of this section.

(A) Detailed schematics, design specifications of the control device, and piping and instrumentation diagrams.

(B) The dates and descriptions of any changes in the design specifications.

(C) A description of the parameter or parameters monitored, as required in a referencing subpart, to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(ii) Records of operation of closed vent systems and control devices, as specified in paragraphs (d)(4)(ii)(A) through (C) of this section.

(A) Dates and durations when the closed vent systems and control devices required are not operated as designed as indicated by the monitored parameters.

(B) Dates and durations during which the monitoring system or monitoring device is inoperative.

(C) Dates and durations of start-ups and shutdowns of control devices required in this subpart.

(5) *Records of monitored parameters outside of range.* The owner or operator shall record the occurrences and the cause of periods when the monitored parameters are outside of the parameter ranges documented in the Notification of Compliance Status report. This information shall also be reported in the Periodic Report.

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999; 71 FR 20458, Apr. 20, 2006]

[↑ Back to Top](#)

§63.999 Notifications and other reports.

(a) *Performance test and flare compliance assessment notifications and reports—(1) General requirements.* General requirements for performance test and flare compliance assessment notifications and reports are specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) The owner or operator shall notify the Administrator of the intention to conduct a performance test or flare compliance assessment at least 30 days before such a compliance demonstration is scheduled to allow the Administrator the opportunity to have an observer present. If after 30 days notice for such an initially scheduled compliance demonstration, there is a delay (due to operational problems, etc.) in conducting the scheduled compliance demonstration, the owner or operator of an affected facility shall notify the Administrator as soon as possible of any delay in the original demonstration date. The owner or operator shall provide at least 7 days prior notice of the rescheduled date of the compliance demonstration, or arrange a rescheduled date with the Administrator by mutual agreement.

(ii) Unless specified differently in this subpart or a referencing subpart, performance test and flare compliance assessment reports, not submitted as part of a Notification of Compliance Status report, shall be submitted to the Administrator within 60 days of completing the test or determination.

(iii) Any application for a waiver of an initial performance test or flare compliance assessment, as allowed by §63.997(b)(2), shall be submitted no later than 90 days before the performance test or compliance assessment is required. The application for a waiver shall include information justifying the owner or operator's request for a waiver, such as the technical or economic infeasibility, or the impracticality, of the source performing the test.

(iv) Any application to substitute a prior performance test or compliance assessment for an initial performance test or compliance assessment, as allowed by §63.997(b)(1), shall be submitted no later than 90 days before the performance test or compliance test is required. The application for substitution shall include information demonstrating that the prior performance test or compliance assessment was conducted using the same methods specified in §63.997(e) or §63.987(b)(3), as applicable. The application shall also include information demonstrating that no process changes have been made since the test, or that the results of the performance test or compliance assessment reliably demonstrate compliance despite process changes.

(2) Performance test and flare compliance assessment report submittal and content requirements. Performance test and flare compliance assessment reports shall be submitted as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For performance tests or flare compliance assessments, the Notification of Compliance Status or performance test and flare compliance assessment report shall include one complete test report as specified in paragraph (a)(2)(ii) of this section for each test method used for a particular kind of emission point and other applicable information specified in (a)(2)(iii) of this section. For additional tests performed for the same kind of emission point using the same method, the results and any other information required in applicable sections of this subpart shall be submitted, but a complete test report is not required.

(ii) A complete test report shall include a brief process description, sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

(iii) The performance test or flare compliance assessment report shall also include the information specified in (a)(2)(iii)(A) through (C) of this section, as applicable.

(A) For flare compliance assessments, the owner or operator shall submit the records specified in §63.998(a)(1)(i).

(B) For nonflare control device and halogen reduction device performance tests as required under §63.988(b), §63.990(b), §63.994(b), or §63.995(b), also submit the records specified in §63.998(a)(2)(ii), as applicable.

(C) For recovery devices also submit the records specified in §63.998(a)(3), as applicable.

(b) Notification of Compliance Status—(1) Routing storage vessel or transfer rack emissions to a process or fuel gas system. An owner or operator who elects to comply with §63.982 by routing emissions from a storage vessel or transfer rack to a process or to a fuel gas system, as specified in §63.984, shall submit as part of the Notification of Compliance Status the information specified in paragraphs (b)(1)(i) and (ii), or (iii) of this section, as applicable.

(i) If storage vessels emissions are routed to a process, the owner or operator shall submit the information specified in §63.984(b)(2) and (3).

(ii) As specified in §63.984(c), if storage vessels emissions are routed to a fuel gas system, the owner or operator shall submit a statement that the emission stream is connected to the fuel gas system and whether the conveyance system is subject to the requirements of §63.983.

(iii) As specified in §63.984(c), report that the transfer rack emission stream is being routed to a fuel gas system or process, when complying with a referencing subpart.

(2) Routing storage vessel or low throughput transfer rack emissions to a nonflare control device. An owner or operator who elects to comply with §63.982 by routing emissions from a storage vessel or low throughput transfer rack to a nonflare control device, as specified in §63.985, shall submit, with the Notification of Compliance Status required by a referencing subpart, the applicable information specified in paragraphs (b)(2)(i) through (vi) of this section. Owners and operators who elect to comply with §63.985(b)(1)(i) by submitting a design evaluation shall submit the information specified in paragraphs (b)(2)(i) through (iv) of this section. Owners and operators who elect to comply with §63.985(b)(1)(ii) by submitting performance test results from a control device for a storage vessel or low throughput transfer rack shall submit the information specified in paragraphs (b)(2)(i), (ii), (iv), and (v) of this section. Owners and operators who elect to comply with §63.985(b)(1)(ii) by submitting performance test results from a shared control device shall submit the information specified in paragraph (b)(2)(vi) of this section.

(i) A description of the parameter or parameters to be monitored to ensure that the control device is being properly operated and maintained, an explanation of the criteria used for selection of that parameter (or parameters), and the frequency with which monitoring will be performed (e.g., when the liquid level in the storage vessel is being raised). If continuous records are specified, indicate whether the provisions of §63.999(c)(6) apply.

(ii) The operating range for each monitoring parameter identified in the monitoring plan required by §63.985(c)(1). The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

(iii) The documentation specified in §63.985(b)(1)(i), if the owner or operator elects to prepare a design evaluation.

(iv) The provisions of paragraph (c)(6) of this section do not apply to any low throughput transfer rack for which the owner or operator has elected to comply with §63.985 or to any storage vessel for which the owner or operator is not required, by the applicable monitoring plan established under §63.985(c)(1), to keep continuous records. If continuous records are required, the owner or operator shall specify in the monitoring plan whether the provisions of paragraph (c)(6) of this section apply.

(v) A summary of the results of the performance test described in §63.985(b)(1)(ii). If such a performance test is conducted, submit the results of the performance test, including the information specified in §63.999(a)(2)(ii) and (iii).

(vi) Identification of the storage vessel or transfer rack and control device for which the performance test will be submitted, and identification of the emission point(s), if any, that share the control device with the storage vessel or transfer rack and for which the performance test will be conducted.

(3) *Operating range for monitored parameters.* The owner or operator shall submit as part of the Notification of Compliance Status, the operating range for each monitoring parameter identified for each control, recovery, or halogen reduction device as determined pursuant to §63.996(c)(6). The specified operating range shall represent the conditions for which the control, recovery, or halogen reduction device is being properly operated and maintained. This report shall include the information in paragraphs (b)(3)(i) through (iii) of this section, as applicable, unless the range and the operating day have been established in the operating permit.

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range indicates proper operation of the control, recovery, or halogen reduction device, as specified in paragraphs (b)(3)(ii)(A), (B), or (C) of this section, as applicable.

(A) If a performance test or TRE index value determination is required by a referencing subpart for a control, recovery or halogen reduction device, the range shall be based on the parameter values measured during the TRE index value determination or performance test and may be supplemented by engineering assessments and/or manufacturer's recommendations. TRE index value determinations and performance testing are not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test or TRE index value determination is not required by a referencing subpart for a control, recovery, or halogen reduction device, the range may be based solely on engineering assessments and/or manufacturer's recommendations.

(C) The range may be based on ranges or limits previously established under a referencing subpart.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) *Halogen reduction device.* The owner or operator shall submit as part of the Notification of Compliance Status the information recorded pursuant to §63.998(a)(4).

(5) *Alternative recordkeeping.* The owner or operator shall notify the Administrator in the Notification of Compliance Status if the alternative recordkeeping requirements of §63.998(b)(5) are being implemented. If the Notification of Compliance Status has already been submitted, the notification must be in the periodic report submitted immediately preceding implementation of the alternative, as specified in paragraph (c)(6)(iv) of this section.

(c) *Periodic reports.* (1) Periodic reports shall include the reporting period dates, the total source operating time for the reporting period, and, as applicable, all information specified in this section and in the referencing subpart, including reports of periods when monitored parameters are outside their established ranges.

(2) For closed vent systems subject to the requirements of §63.983, the owner or operator shall submit as part of the periodic report the information specified in paragraphs (c)(2)(i) through (iii) of this section, as applicable.

(i) The information recorded in §63.998(d)(1)(iii)(B) through (E);

(ii) Reports of the times of all periods recorded under §63.998(d)(1)(ii)(A) when the vent stream is diverted from the control device through a bypass line; and

(iii) Reports of all times recorded under §63.998(d)(1)(ii)(B) when maintenance is performed in car-sealed valves, when the seal is broken, when the bypass line valve position is changed, or the key for a lock-and-key type configuration has been checked out.

(3) For flares subject to this subpart, report all periods when all pilot flames were absent or the flare flame was absent as recorded in §63.998(a)(1)(i)(C).

(4) For storage vessels, the owner or operator shall include in each periodic report required the information specified in paragraphs (c)(4)(i) through (iii) of this section.

(i) For the 6-month period covered by the periodic report, the information recorded in §63.998(d)(2)(ii)(A) through (C).

(ii) For the time period covered by the periodic report and the previous periodic report, the total number of hours that the control system did not meet the requirements of §63.983(a), §63.985(a), or §63.987(a) due to planned routine maintenance.

(iii) A description of the planned routine maintenance during the next 6-month periodic reporting period that is anticipated to be performed for the control system when it is not expected to meet the required control efficiency. This description shall include the type of maintenance necessary, planned frequency of maintenance, and expected lengths of maintenance periods.

(5) If a control device other than a flare is used to control emissions from storage vessels or low throughput transfer racks, the periodic report shall describe each occurrence when the monitored parameters were outside of the parameter ranges documented in the Notification of Compliance

Status in accordance with paragraph (b)(3) of this section. The description shall include the information specified in paragraphs (c)(5)(i) and (ii) of this section.

(i) Identification of the control device for which the measured parameters were outside of the established ranges, and

(ii) The cause for the measured parameters to be outside of the established ranges.

(6) For process vents and transfer racks (except low throughput transfer racks), periodic reports shall include the information specified in paragraphs (c)(6)(i) through (iv) of this section.

(i) Periodic reports shall include the daily average values of monitored parameters, calculated as specified in §63.998(b)(3)(i) for any days when the daily average value is outside the bounds as defined in §63.998(c)(2)(iii) or (c)(3)(iii), or the data availability requirements defined in paragraphs (c)(6)(i)(A) through (D) of this section are not met, whether these excursions are excused or unexcused excursions. For excursions caused by lack of monitoring data, the duration of periods when monitoring data were not collected shall be specified. An excursion means any of the cases listed in paragraphs (c)(6)(i)(A) through (C) of this section. If the owner or operator elects not to retain the daily average values pursuant to §63.998(b)(5)(ii)(A), the owner or operator shall report this in the Periodic Report.

(A) When the daily average value of one or more monitored parameters is outside the permitted range.

(B) When the period of control or recovery device operation is 4 hours or greater in an operating day and monitoring data are insufficient to constitute a valid hour of data for at least 75 percent of the operating hours.

(C) When the period of control or recovery device operation is less than 4 hours in an operating day and more than one of the hours during the period of operation does not constitute a valid hour of data due to insufficient monitoring data.

(D) Monitoring data are insufficient to constitute a valid hour of data as used in paragraphs (c)(6)(i)(B) and (C) of this section, if measured values are unavailable for any of the 15-minute periods within the hour.

(ii) Report all carbon-bed regeneration cycles during which the parameters recorded under §63.998(a)(2)(ii)(C) were outside the ranges established in the Notification of Compliance Status or in the operating permit.

(iii) The provisions of paragraph (c)(6)(i) and (ii) of this section do not apply to any low throughput transfer rack for which the owner or operator has elected to comply with §63.985 or to any storage vessel for which the owner or operator is not required, by the applicable monitoring plan established under §63.985(c)(1), to keep continuous records. If continuous records are required, the owner or operator shall specify in the monitoring plan whether the provisions of paragraphs (c)(6)(i) and (c)(6)(ii) of this section apply.

(iv) If the owner or operator has chosen to use the alternative recordkeeping requirements of §63.998(b)(5), and has not notified the Administrator in the Notification of Compliance Status that the alternative recordkeeping provisions are being implemented as specified in paragraph (b)(5) of this section, the owner or operator shall notify the Administrator in the Periodic Report submitted immediately preceding implementation of the alternative. The notifications specified in §63.998(b)(5)(ii) shall be included in the next Periodic Report following the identified event.

(7) As specified in §63.997(c)(3), if an owner or operator at a facility not required to obtain a title V permit elects at a later date to replace an existing control or recovery device with a different control or recovery device, then the Administrator shall be notified by the owner or operator before implementing the change. This notification may be included in the facility's periodic reporting.

(d) *Requests for approval of monitoring alternatives*—(1) *Alternatives to the continuous operating parameter monitoring and recordkeeping provisions.* Requests for approval to use alternatives to continuous operating parameter monitoring and recordkeeping provisions, as provided for in §63.996(d)(1), shall be submitted as specified in a referencing subpart, and the referencing subpart will govern the review and approval of such requests. The information specified in paragraphs (d)(1)(i) and (ii) of this section shall be included.

(i) A description of the proposed alternative system; and

(ii) Information justifying the owner or operator's request for an alternative method, such as the technical or economic infeasibility, or the impracticality, of the regulated source using the required method.

(2) *Monitoring a different parameter than those listed.* Requests for approval to monitor a different parameter than those established in §63.996(c)(6) of this section or to set unique monitoring parameters, as provided for in §63.996(d)(2), shall be submitted as specified as specified in a referencing subpart, and the referencing subpart will govern the review and approval of such requests. The information specified in paragraphs (d)(2)(i) through (iii) of this section shall be included in the request.

(i) A description of the parameter(s) to be monitored to ensure the control technology or pollution prevention measure is operated in conformance with its design and achieves the specified emission limit, percent reduction, or nominal efficiency, and an explanation of the criteria used to select the parameter(s);

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device, the schedule for this demonstration, and a statement that the owner or operator will establish a range for the monitored parameter(s) as part of the Notification of Compliance Status if required under a referencing subpart, unless this information has already been submitted; and

(iii) The frequency and content of monitoring, recording, and reporting, if monitoring and recording is not continuous, or if reports of daily average values when the monitored parameter

value is outside the established range will not be included in periodic reports under paragraph (c) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

[64 FR 34866, June 29, 1999, as amended at 64 FR 63705, Nov. 22, 1999]

Appendix P

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

Contents

[What This Subpart Covers](#)

- [§63.1560 What is the purpose of this subpart?](#)
- [§63.1561 Am I subject to this subpart?](#)
- [§63.1562 What parts of my plant are covered by this subpart?](#)
- [§63.1563 When do I have to comply with this subpart?](#)

[Catalytic Cracking Units, Catalytic Reforming Units, Sulfur Recovery Units, and Bypass Lines](#)

- [§63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?](#)
- [§63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?](#)
- [§63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?](#)
- [§63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?](#)
- [§63.1568 What are my requirements for HAP emissions from sulfur recovery units?](#)
- [§63.1569 What are my requirements for HAP emissions from bypass lines?](#)

[General Compliance Requirements](#)

- [§63.1570 What are my general requirements for complying with this subpart?](#)
- [§63.1571 How and when do I conduct a performance test or other initial compliance demonstration?](#)
- [§63.1572 What are my monitoring installation, operation, and maintenance requirements?](#)
- [§63.1573 What are my monitoring alternatives?](#)

[Notifications, Reports, and Records](#)

- [§63.1574 What notifications must I submit and when?](#)
- [§63.1575 What reports must I submit and when?](#)
- [§63.1576 What records must I keep, in what form, and for how long?](#)

[Other Requirements and Information](#)

- [§63.1577 What parts of the General Provisions apply to me?](#)
- [§63.1578 Who implements and enforces this subpart?](#)
- [§63.1579 What definitions apply to this subpart?](#)
- [Table 1 to Subpart UUU of Part 63—Metal HAP Emission Limits for Catalytic Cracking Units](#)
- [Table 2 to Subpart UUU of Part 63—Operating Limits for Metal HAP Emissions From Catalytic](#)

Cracking Units

Table 3 to Subpart UUU of Part 63—Continuous Monitoring Systems for Metal HAP Emissions From Catalytic Cracking Units

Table 4 to Subpart UUU of Part 63—Requirements for Performance Tests for Metal HAP Emissions From Catalytic Cracking Units

Table 5 to Subpart UUU of Part 63—Initial Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

Table 6 to Subpart UUU of Part 63—Continuous Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

Table 7 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

Table 8 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Cracking Units

Table 9 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

Table 10 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Cracking Units

Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)

Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

Table 13 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

Table 14 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

Table 15 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Reforming Units

Table 16 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

Table 17 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Reforming Units

Table 18 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Reforming Units

Table 19 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

Table 20 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

Table 21 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

Table 22 to Subpart UUU of Part 63—Inorganic HAP Emission Limits for Catalytic Reforming Units

Table 23 to Subpart UUU of Part 63—Operating Limits for Inorganic HAP Emission Limitations for Catalytic Reforming Units

Table 24 to Subpart UUU of Part 63—Continuous Monitoring Systems for Inorganic HAP Emissions From Catalytic Reforming Units

[Table 25 to Subpart UUU of Part 63—Requirements for Performance Tests for Inorganic HAP Emissions From Catalytic Reforming Units](#)

[Table 26 to Subpart UUU of Part 63—Initial Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units](#)

[Table 27 to Subpart UUU of Part 63—Continuous Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units](#)

[Table 28 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Inorganic HAP Emissions From Catalytic Reforming Units](#)

[Table 29 to Subpart UUU of Part 63—HAP Emission Limits for Sulfur Recovery Units](#)

[Table 30 to Subpart UUU of Part 63—Operating Limits for HAP Emissions From Sulfur Recovery Units](#)

[Table 31 to Subpart UUU of Part 63—Continuous Monitoring Systems for HAP Emissions From Sulfur Recovery Units](#)

[Table 32 to Subpart UUU of Part 63—Requirements for Performance Tests for HAP Emissions From Sulfur Recovery Units Not Subject to the New Source Performance Standards for Sulfur Oxides](#)

[Table 33 to Subpart UUU of Part 63—Initial Compliance With HAP Emission Limits for Sulfur Recovery Units](#)

[Table 34 to Subpart UUU of Part 63—Continuous Compliance With HAP Emission Limits for Sulfur Recovery Units](#)

[Table 35 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for HAP Emissions From Sulfur Recovery Units](#)

[Table 36 to Subpart UUU of Part 63—Work Practice Standards for HAP Emissions From Bypass Lines](#)

[Table 37 to Subpart UUU of Part 63—Requirements for Performance Tests for Bypass Lines](#)

[Table 38 to Subpart UUU of Part 63—Initial Compliance With Work Practice Standards for HAP Emissions From Bypass Lines](#)

[Table 39 to Subpart UUU of Part 63—Continuous Compliance With Work Practice Standards for HAP Emissions From Bypass Lines](#)

[Table 40 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Opacity Monitoring Systems and Continuous Emission Monitoring Systems](#)

[Table 41 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Parameter Monitoring Systems](#)

[Table 42 to Subpart UUU of Part 63—Additional Information for Initial Notification of Compliance Status](#)

[Table 43 to Subpart UUU of Part 63—Requirements for Reports](#)

[Table 44 to Subpart UUU of Part 63—Applicability of NESHAP General Provisions to Subpart UUU](#)

[Appendix A to Subpart UUU of Part 63—Determination of Metal Concentration on Catalyst Particles \(Instrumental Analyzer Procedure\)](#)

SOURCE: 67 FR 17773, Apr. 11, 2002, unless otherwise noted.

[↑ Back to Top](#)

What This Subpart Covers

↑ [Back to Top](#)

§63.1560 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (HAP) emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

↑ [Back to Top](#)

§63.1561 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a petroleum refinery that is located at a major source of HAP emissions.

(1) A petroleum refinery is an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411, and used mainly for:

(i) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(ii) Separating petroleum; or

(iii) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

(2) A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

(b) [Reserved]

↑ [Back to Top](#)

§63.1562 What parts of my plant are covered by this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery.

(b) The affected sources are:

(1) The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (*i.e.*, the catalyst regeneration flue gas vent).

(2) The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation.

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants that are associated with sulfur recovery.

(4) Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

(c) An affected source is a new affected source if you commence construction of the affected source after September 11, 1998, and you meet the applicability criteria in §63.1561 at the time you commenced construction.

(d) Any affected source is reconstructed if you meet the criteria in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

(f) This subpart does not apply to:

(1) A thermal catalytic cracking unit.

(2) A sulfur recovery unit that does not recover elemental sulfur or where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process).

(3) A redundant sulfur recovery unit not located at a petroleum refinery and used by the refinery only for emergency or maintenance backup.

(4) Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons.

(5) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are subject to §63.670.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75273, Dec. 1, 2015]

§63.1563 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002 except as provided in paragraph (d) of this section.

(2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source except as provided in paragraph (d) of this section.

(b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraphs (c) and (d) of this section.

(c) We will grant an extension of compliance for an existing catalytic cracking unit allowing additional time to meet the emission limitations and work practice standards for catalytic cracking units in §§63.1564 and 63.1565 if you commit to hydrotreating the catalytic cracking unit feedstock and to meeting the emission limitations of this subpart on the same date that your facility meets the final Tier 2 gasoline sulfur control standard (40 CFR part 80, subpart J). To obtain an extension, you must submit a written notification to your permitting authority according to the requirements in §63.1574(e). Your notification must include the information in paragraphs (c)(1) and (2) of this section.

(1) Identification of the affected source with a brief description of the controls to be installed (if needed) to comply with the emission limitations for catalytic cracking units in this subpart.

(2) A compliance schedule, including the information in paragraphs (c)(2)(i) through (iv) of this section.

(i) The date by which onsite construction or the process change is to be initiated.

(ii) The date by which onsite construction or the process change is to be completed.

(iii) The date by which your facility will achieve final compliance with both the final Tier 2 gasoline sulfur control standard as specified in §80.195, and the emission limitations and work practice standards for catalytic cracking units in this subpart. In no case will your permitting authority grant an extension beyond the date you are required to meet the Tier 2 gasoline sulfur control standard or December 31, 2009, whichever comes first. If you don't comply with the emission limitations and work practice standards for existing catalytic cracking units by the specified date, you will be out-of-compliance with the requirements for catalytic cracking units beginning April 11, 2005.

(iv) A brief description of interim emission control measures that will be taken to ensure proper operation and maintenance of the process equipment during the period of the compliance extension.

(d) You must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) as specified in paragraph (d)(1) or (2) of this section, as applicable.

(1) For sources which commenced construction or reconstruction before June 30, 2014, you must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before August 1, 2017 unless an extension is requested and approved in accordance with the provisions in §63.6(i). After February 1, 2016 and prior to the date of compliance with the provisions in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4), you must comply with the requirements in §63.1570(c) and (d).

(2) For sources which commenced construction or reconstruction on or after June 30, 2014, you must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before February 1, 2016 or upon startup, whichever is later.

(e) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the requirements in paragraphs (e)(1) and (2) of this section apply.

(1) Any portion of the existing facility that is a new affected source or a new reconstructed source must be in compliance with the requirements of this subpart upon startup.

(2) All other parts of the source must be in compliance with the requirements of this subpart by no later than 3 years after it becomes a major source or, if applicable, the extended compliance date granted according to the requirements in paragraph (c) of this section.

(f) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart.

[67 FR 17773, Apr. 11, 2002, as amended at 81 FR 45243, July 13, 2016]

[!\[\]\(f95dab70c751fda7d824b8b03650f7aa_img.jpg\) Back to Top](#)

Catalytic Cracking Units, Catalytic Reforming Units, Sulfur Recovery Units, and Bypass Lines

[!\[\]\(d8ab143e904bfa3467271eec5af75a9b_img.jpg\) Back to Top](#)

§63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter or is subject to §60.102a(b)(1) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for PM, you can choose from the six options in paragraphs (a)(1)(i) through (vi) of this section:

(i) You can elect to comply with the NSPS for PM in §60.102 of this chapter (Option 1a);

(ii) You can elect to comply with the NSPS for PM coke burn-off emission limit in §60.102a(b)(1) of this chapter (Option 1b);

(iii) You can elect to comply with the NSPS for PM concentration limit in §60.102a(b)(1) of this chapter (Option 1c);

(iv) You can elect to comply with the PM per coke burn-off emission limit (Option 2);

(v) You can elect to comply with the Nickel (Ni) lb/hr emission limit (Option 3); or

(vi) You can elect to comply with the Ni per coke burn-off emission limit (Option 4).

(2) Comply with each operating limit in Table 2 of this subpart that applies to you. When a specific control device may be monitored using more than one continuous parameter monitoring system, you may select the parameter with which you will comply. You must provide notice to the Administrator (or other designated authority) if you elect to change the monitoring option.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(5) On or before the date specified in §63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown and hot standby:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section, except catalytic cracking units controlled using a wet scrubber must maintain only the liquid to gas ratio operating limit (the pressure drop operating limit does not apply); or

(ii) You can elect to maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 3 of this subpart.

(2) Conduct a performance test for each catalytic cracking unit according to the requirements in §63.1571 and under the conditions specified in Table 4 of this subpart.

(3) Establish each site-specific operating limit in Table 2 of this subpart that applies to you according to the procedures in Table 4 of this subpart.

(4) Use the procedures in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) If you elect Option 1b or Option 2 in paragraph (a)(1)(ii) or (iv) of this section, compute the PM emission rate (lb/1,000 lb of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section and the site-specific opacity limit, if applicable, using Equation 4 of this section as follows:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left[\left(\frac{\%CO}{2} \right) + \%CO_2 + \%O_2 \right] + K_4 Q_{avg} (\%O_{avg}) \quad (\text{Eq. 1})$$

[View or download PDF](#)

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either §63.1573(a)(1) or (2), as applicable, to calculate Q_r ;

Q_a = Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%CO$ = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) (0.0186 (lb-min)/(hr-dscf-%));

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) (0.1303 (lb-min)/(hr-dscf));

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) (0.0062 (lb-min)/(hr-dscf-%));

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); and

% O_{xy} = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \quad (\text{Eq. 2})$$

[View or download PDF](#)

Where:

E = Emission rate of PM, kg/1,000 kg (lb/1,000 lb) of coke burn-off;

C_s = Concentration of PM, g/dscm (lb/dscf);

Q_{sd} = Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A-1 to part 60 of this chapter, dscm/hr (dscf/hr);

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 (kg²/g)/(1,000 kg) (1,000 lb/(1,000 lb)).

$$E_s = 1.0 + A \left(\frac{H}{R_c} \right) K^* \quad (\text{Eq. 3})$$

[View or download PDF](#)

Where:

E_s = Emission rate of PM allowed, kg/1,000 kg (lb/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions. Before August 1, 2017, A = 0.18 g/million cal (0.10 lb/million Btu). On or after August 1, 2017, A = 0 g/million cal (0 lb/million Btu);

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate;

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K' = Conversion factor to units to standard, 1.0 (kg₂/g)/(1,000 kg) (10₃ lb/(1,000 lb)).

$$Opacity\ Limit = Opacity_{st} \times \left(\frac{1\ lb / 1000\ lb\ coke\ burn}{PME mR_{st}} \right) \quad (Eq. 4)$$

[View or download PDF](#)

Where:

Opacity Limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

Opacity_{st} = Hourly average opacity measured during the source test, percent; and

PME mR_{st} = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(ii) If you elect Option 1c in paragraph (a)(1)(iii) of this section, the PM concentration emission limit, determine the average PM concentration from the initial performance test used to certify your PM CEMS.

(iii) If you elect Option 3 in paragraph (a)(1)(iii) of this section, the Ni lb/hr emission limit, compute your Ni emission rate using Equation 5 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 6 and 7 of this section as follows:

$$E_{Ni} = C_{Ni} \times Q_{std} \quad (Eq. 5)$$

[View or download PDF](#)

Where:

E_{Ni} = Mass emission rate of Ni, mg/hr (lb/hr); and

C_{Ni} = Ni concentration in the catalytic cracking unit catalyst regenerator flue gas as measured by Method 29 in appendix A to part 60 of this chapter, mg/dscm (lbs/dscf).

$$Opacity_1 = \frac{13\ g\ Ni/hr}{NiEmR\ 1_{st}} \times Opacity_{st} \quad (Eq. 6)$$

[View or download PDF](#)

Where:

Opacity₁ = Opacity value for use in Equation 7 of this section, percent, or 10 percent, whichever is greater; and

NiEmR1_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each of the performance test runs, g Ni/hr.

$$Ni \text{ Operating Limit}_1 = Opacity_1 \times Q_{mon,st} \times E-Cat_{st} \quad (Eq. 7)$$

[View or download PDF](#)

Where:

Ni operating limit₁ = Maximum permissible hourly average Ni operating limit, percent-acfm-ppmw, i.e., your site-specific Ni operating limit;

Q_{mon,st} = Hourly average actual gas flow rate as measured by the continuous parameter monitoring system during the performance test or using the alternative procedure in §63.1573, acfm; and

E-Cat_{st} = Ni concentration on equilibrium catalyst measured during source test, ppmw.

(iv) If you elect Option 4 in paragraph (a)(1)(vi) of this section, the Ni per coke burn-off emission limit, compute your Ni emission rate using Equations 1 and 8 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 9 and 10 of this section as follows:

$$E_{Ni} = \frac{C_{Ni} \times Q_{sd}}{R_c} \quad (Eq. 8)$$

[View or download PDF](#)

Where:

E_{Ni2} = Normalized mass emission rate of Ni, mg/kg coke (lb/1,000 lb coke).

$$Opacity_2 = \frac{1.0 \text{ mg/kg coke}}{NiEmR2_{sd}} \times Opacity_{sd} \quad (Eq. 9)$$

[View or download PDF](#)

Where:

Opacity₂ = Opacity value for use in Equation 10 of this section, percent, or 10 percent, whichever is greater; and

NiEmR2_{st} = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of this section for each of the performance test runs, mg/kg coke.

$$Ni\ Operating\ Limit_2 = Opacity_2 \times E-Cat_{st} \times \frac{Q_{mon,st}}{R_{c,st}} \quad (Eq. 10)$$

[View or download PDF](#)

Where:

Ni Operating Limit₂ = Maximum permissible hourly average Ni operating limit, percent-ppmw-acfm-hr/kg coke, *i.e.*, your site-specific Ni operating limit; and

R_{c,st} = Coke burn rate from Equation 1 of this section, as measured during the initial performance test, kg coke/hr.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan.

(3) If you use a continuous opacity monitoring system and elect to comply with Option 3 in paragraph (a)(1)(iii) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as follows:

$$Ni\ Operating\ Value_1 = Opacity \times Q_{mon} \times E-Cat \quad (Eq. 11)$$

[View or download PDF](#)

Where:

Ni operating value₁ = Maximum permissible hourly average Ni standard operating value, %-acfm-ppmw;

Opacity = Hourly average opacity, percent;

Q_{mon} = Hourly average actual gas flow rate as measured by continuous parameter monitoring system or calculated by alternative procedure in §63.1573, acfm; and

E-Cat = Ni concentration on equilibrium catalyst from weekly or more recent measurement, ppmw.

(4) If you use a continuous opacity monitoring system and elect to comply with Option 4 in paragraph (a)(1)(iv) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 12 of this section as follows:

$$\text{Ni Operating Value}_2 = \frac{\text{Opacity} \times E\text{-Cat} \times Q_{\text{mon}}}{R_c} \quad (\text{Eq. 12})$$

[View or download PDF](#)

Where:

Ni operating value₂ = Maximum permissible hourly average Ni standard operating value, percent-acfm-ppmw-hr/kg coke.

(5) If you elect to comply with the alternative limit in paragraph (a)(5)(ii) of this section during periods of startup, shutdown and hot standby, demonstrate continuous compliance on or before the date specified in §63.1563(d) by:

(i) Collecting the volumetric flow rate from the catalyst regenerator (in acfm) and determining the average flow rate for each hour. For events lasting less than one hour, determine the average flow rate during the event.

(ii) Determining the cumulative cross-sectional area of the primary internal cyclone inlets in square feet (ft²) using design drawings of the primary (first-stage) internal cyclones to determine the inlet cross-sectional area of each primary internal cyclone and summing the cross-sectional areas for all primary internal cyclones in the catalyst regenerator or, if primary cyclones are identical, you may alternatively determine the inlet cross-sectional area of one primary internal cyclone using design drawings and multiply that area by the total number of primary internal cyclones in the catalyst regenerator.

(iii) Calculating the inlet velocity to the primary internal cyclones in square feet per second (ft²/sec) by dividing the average volumetric flow rate (acfm) by the cumulative cross-sectional area of the primary internal cyclone inlets (ft²) and by 60 seconds/minute (for unit conversion).

(iv) Maintaining the inlet velocity to the primary internal cyclones at or above 20 feet per second for each hour during the startup, shutdown, or hot standby event or, for events lasting less than 1 hour, for the duration of the event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75273, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

[↑ Back to Top](#)

§63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter or is subject to §60.102a(b)(4) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1); or

(ii) You can elect to comply with the CO emission limit (Option 2).

(2) Comply with each site-specific operating limit in Table 9 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(5) On or before the date specified in §63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown and hot standby:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section; or

(ii) You can elect to maintain the oxygen (O₂) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis).

(b) How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 10 of this subpart. Except:

(i) Whether or not your catalytic cracking unit is subject to the NSPS for CO in §60.103 of this chapter, you don't have to install and operate a continuous emission monitoring system if you show that CO emissions from your vent average less than 50 parts per million (ppm), dry basis. You must get an exemption from your permitting authority, based on your written request. To show that the emissions average is less than 50 ppm (dry basis), you must continuously monitor CO emissions for 30 days using a CO continuous emission monitoring system that meets the requirements in §63.1572.

(ii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler (including a "CO boiler") or process heater that has a design heat input capacity of at least 44 megawatts (MW).

(iii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler or process heater in which all vent streams are introduced into the flame zone.

(2) Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in §63.1571 and under the conditions specified in Table 11 of this subpart.

(3) Establish each site-specific operating limit in Table 9 of this subpart that applies to you according to the procedures in Table 11 of this subpart.

(4) Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart.

(5) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status according to §63.1574.

(6) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 1, 2002, as amended at 80 FR 75275, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

[↑ Back to Top](#)

§63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) and (ii) of this section.

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare (Option 1). On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.

(ii) You can elect to meet a TOC or nonmethane TOC percent reduction standard or concentration limit, whichever is less stringent (Option 2).

(2) Comply with each site-specific operating limit in Table 16 of this subpart that applies to you.

(3) Except as provided in paragraph (a)(4) of this section, the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents.

(4) The emission limitations in tables 15 and 16 of this subpart do not apply to emissions from process vents during passive depressuring when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less or during active depressuring or purging prior to January 30, 2019, when the reactor vent pressure is 5 psig or less. On and after January 30, 2019, the emission limitations in tables 15 and 16 of this subpart do apply to emissions from process vents during active purging operations (when nitrogen or other purge gas is actively introduced to the reactor

vessel) or active depressuring (using a vacuum pump, ejector system, or similar device) regardless of the reactor vent pressure.

(5) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 17 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and under the conditions specified in Table 18 of this subpart.

(3) Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart.

(4) Use the procedures in paragraph (b)(4)(i) or (ii) of this section to determine initial compliance with the emission limitations.

(i) If you elect the percent reduction standard under Option 2, calculate the emission rate of nonmethane TOC using Equation 1 of this section (if you use Method 25) or Equation 2 of this section (if you use Method 25A or Methods 25A and 18), then calculate the mass emission reduction using Equation 3 of this section as follows:

$$E = K_4 M_c Q_s \quad (\text{Eq. 1})$$

[View or download PDF](#)

Where:

E = Emission rate of nonmethane TOC in the vent stream, kilograms-C per hour;

K_4 = Constant, 6.0×10^{-5} (kilograms per milligram)(minutes per hour);

M_c = Mass concentration of total gaseous nonmethane organic (as carbon) as measured and calculated using Method 25 in appendix A to part 60 of this chapter, mg/dscm; and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees Celsius (C).

$$E = K_5 \left(C_{\text{TOC}} - \frac{1}{6} C_{\text{methane}} \right) Q_s \quad (\text{Eq. 2})$$

[View or download PDF](#)

Where:

K_s = Constant, 1.8×10^{-4} (parts per million)⁻¹ (gram-mole per standard cubic meter) (gram-C per gram-mole-hexane) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees C (uses 72g-C/g.mole hexane);

C_{TOC} = Concentration of TOC on a dry basis in ppmv as hexane as measured by Method 25A in appendix A to part 60 of this chapter;

C_{methane} = Concentration of methane on a dry basis in ppmv as measured by Method 18 in appendix A to part 60 of this chapter. If the concentration of methane is not determined, assume C_{methane} equals zero; and

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 degrees C.

$$\% \text{ reduction} = \frac{E_i - E_o}{E_i} \times 100\% \quad (\text{Eq. 3})$$

[View or download PDF](#)

Where:

E_i = Mass emission rate of TOC at control device inlet, kg/hr; and

E_o = Mass emission rate of TOC at control device outlet, kg/hr.

(ii) If you elect the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen (O_2) content in the gas stream using Equation 4 of this section as follows:

$$C_{\text{NMTOC, 3\%O}_2} = (C_{\text{TOC}} - \frac{1}{6} C_{\text{methane}}) \left(\frac{17.9\%}{20.9\% - \%O_2} \right) \quad (\text{Eq. 4})$$

[View or download PDF](#)

Where:

$C_{\text{NMTOC, 3\%O}_2}$ = Concentration of nonmethane TOC on a dry basis in ppmv as hexane corrected to 3 percent oxygen.

(5) You are not required to do a TOC performance test if:

(i) You elect to vent emissions to a flare as provided in paragraph (a)(1)(i) of this section (Option 1); or

(ii) You elect the TOC percent reduction or concentration limit in paragraph (a)(1)(ii) of this section (Option 2), and you use a boiler or process heater with a design heat input capacity of 44 MW or greater or a boiler or process heater in which all vent streams are introduced into the flame zone.

(6) Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart.

(7) Demonstrate initial compliance with the work practice standard in paragraph (a)(5) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(8) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart.

(2) Demonstrate continuous compliance with the work practice standards in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75275, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

[!\[\]\(0b5e7e25e8775f7e7e80906ada4f0021_img.jpg\) Back to Top](#)

§63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet a percent reduction standard for hydrogen chloride (HCl) emissions (Option 1); or

(ii) You can elect to meet an HCl concentration limit (Option 2).

(2) Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 24 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and the conditions specified in Table 25 of this subpart.

(3) Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart.

(4) Use the equations in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) Correct the measured HCl concentration for oxygen (O₂) content in the gas stream using Equation 1 of this section as follows:

$$C_{\text{HCl}, 3\% \text{O}_2} = \left(\frac{17.9\%}{20.9\% - \% \text{O}_2} \right) C_{\text{HCl}} \quad (\text{Eq. 1})$$

[View or download PDF](#)

Where:

$C_{\text{HCl}, 3\% \text{O}_2}$ = Concentration of HCl on a dry basis in ppmv corrected to 3 percent oxygen or 1 ppmv, whichever is greater;

C_{HCl} = Concentration of HCl on a dry basis in ppmv, as measured by Method 26A in 40 CFR part 60, appendix A; and

$\% \text{O}_2$ = Oxygen concentration in percent by volume (dry basis).

(ii) If you elect the percent reduction standard, calculate the emission rate of HCl using Equation 2 of this section; then calculate the mass emission reduction from the mass emission rates using Equation 3 of this section as follows:

$$E_{\text{HCl}} = K_6 C_{\text{HCl}} Q_s \quad (\text{Eq. 2})$$

[View or download PDF](#)

Where:

E_{HCl} = Emission rate of HCl in the vent stream, grams per hour;

K_6 = Constant, $0.091 \text{ (parts per million)}^{-1}$ (grams HCl per standard cubic meter) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees Celsius (C); and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees C.

$$\text{HCl\%reduction} = \frac{E_{\text{HCl},i} - E_{\text{HCl},o}}{E_{\text{HCl},i}} \times 100\% \quad (\text{Eq. 3})$$

[View or download PDF](#)

Where:

$E_{\text{HCl},i}$ = Mass emission rate of HCl at control device inlet, g/hr; and

$E_{\text{HCl},o}$ = Mass emission rate of HCl at control device outlet, g/hr.

(iii) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the HCl concentration operating limit, calculate the HCl operating limit using Equation 4 of this section as follows:

$$C_{\text{HCl,ppmvLimit}} = 0.9 C_{\text{HCl,AveTube}} \left(\frac{C_{\text{HCl,RegLimit}}}{C_{\text{HCl}, 3\%O_2}} \right) \quad (\text{Eq. 4})$$

[View or download PDF](#)

Where:

$C_{\text{HCl,ppmvLimit}}$ = Maximum permissible HCl concentration for the HCl concentration operating limit, ppmv;

$C_{\text{HCl,AveTube}}$ = Average HCl concentration from the colormetric tube sampling system, calculated as the arithmetic average of the average HCl concentration measured for each performance test run, ppmv or 1 ppmv, whichever is greater; and

$C_{\text{HCl,RegLimit}}$ = Maximum permissible outlet HCl concentration for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 10 or 30 ppmv.

(iv) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the percent reduction operating limit, calculate the HCl operating limit using Equation 5 of this section as follows:

$$C_{\text{HCl, \%Limit}} = 0.9 C_{\text{HCl, AveTube}} \left(\frac{100 - \% \text{HClReduction}_{\text{Limit}}}{100 - \% \text{HClReduction}_{\text{Test}}} \right) \quad (\text{Eq. 5})$$

[View or download PDF](#)

Where:

$C_{\text{HCl, \%Limit}}$ = Maximum permissible HCl concentration for the percent reduction operating limit, ppmv;

$\% \text{HCl Reduction}_{\text{Limit}}$ = Minimum permissible HCl reduction for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 97 or 92 percent; and

$\% \text{HCl Reduction}_{\text{Test}}$ = Average percent HCl reduction calculated as the arithmetic average HCl reduction calculated using Equation 3 of this section for each performance source test, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standard?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6939, Feb. 9, 2005]

[↑ Back to Top](#)

§63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) *What emission limitations and work practice standard must I meet?* You must:

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in §60.104 or §60.102a(f)(1) of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit is not subject to one of these NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet the NSPS requirements in §60.104(a)(2) or §60.102a(f)(1) of this chapter (Option 1); or

(ii) You can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) Meet each operating limit in Table 30 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) On or before the date specified in §63.1563(d), you must comply with one of the three options in paragraphs (a)(4)(i) through (iii) of this section during periods of startup and shutdown.

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section.

(ii) You can elect to send any startup or shutdown purge gases to a flare. On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the design and operating requirements in §63.11(b) or the requirements of §63.670.

(iii) You can elect to send any startup or shutdown purge gases to a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1,200 degrees Fahrenheit in the firebox and a minimum hourly average outlet oxygen (O₂) concentration of 2 volume percent (dry basis).

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.

(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in §63.1571 and under the conditions specified in Table 32 of this subpart.

(3) Establish each site-specific operating limit in Table 30 of this subpart that applies to you according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as follows:

$$C_{adj} = C_{meas} \left[20.9_c / (20.9 - \%O_2) \right] \quad (Eq. 1)$$

[View or download PDF](#)

Where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent oxygen—0.0 percent oxygen (defined oxygen correction basis), percent;

20.9 = oxygen concentration in air, percent;

$\%O_2$ = oxygen concentration measured on a dry basis, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75275, Dec. 1, 2015; 81 FR 45244, July 13, 2016]

[↑ Back to Top](#)

§63.1569 What are my requirements for HAP emissions from bypass lines?

(a) *What work practice standards must I meet?* (1) You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to install an automated system (Option 1);

(ii) You can elect to use a manual lock system (Option 2);

(iii) You can elect to seal the line (Option 3); or

(iv) You can elect to vent to a control device (Option 4).

(2) As provided in §63.6(g), we, the EPA, may choose to grant you permission to use an alternative to the work practice standard in paragraph (a)(1) of this section.

(3) You must prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the work practice standards?* You must:

(1) If you elect the option in paragraph (a)(1)(i) of this section, conduct each performance test for a bypass line according to the requirements in §63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the work practice standards? You must:*

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[↑ Back to Top](#)

General Compliance Requirements

[↑ Back to Top](#)

§63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart at all times.

(b) You must be in compliance with the opacity and visible emission limits in this subpart at all times.

(c) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(d) During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log that documents the procedures used to minimize emissions from process and emissions control equipment according to the general duty in paragraph (c) of this section.

(e) [Reserved]

(f) You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.1575.

[67 FR 17773, Apr. 11, 2002, as amended at 71 FR 20462, Apr. 20, 2006; 80 FR 75276, Dec. 1, 2015]

[↑ Back to Top](#)

§63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test.

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §63.1563.

(2) For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for your source in §63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in §63.1563.

(3) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, you must demonstrate initial compliance with either the proposed emission limitation or the promulgated emission limitation no later than October 8, 2002 or within 180 calendar days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(4) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, and you chose to comply with the proposed emission limitation when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limitation by October 10, 2005, or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(5) *Periodic performance testing for PM or Ni.* Except as provided in paragraphs (a)(5)(i) and (ii) of this section, conduct a periodic performance test for PM or Ni for each catalytic cracking unit at least once every 5 years according to the requirements in Table 4 of this subpart. You must conduct the first periodic performance test no later than August 1, 2017.

(i) Catalytic cracking units monitoring PM concentration with a PM CEMS are not required to conduct a periodic PM performance test.

(ii) Conduct a performance test annually if you comply with the emission limits in Item 1 (NSPS subpart J) or Item 4 (Option 1a) in Table 1 of this subpart and the PM emissions measured during the most recent performance source test are greater than 0.80 g/kg coke burn-off.

(6) *One-time performance testing for HCN.* Conduct a performance test for HCN from each catalytic cracking unit no later than August 1, 2017 according to the applicable requirements in paragraphs (a)(6)(i) and (ii) of this section.

(i) If you conducted a performance test for HCN for a specific catalytic cracking unit between March 31, 2011 and February 1, 2016, you may submit a request to the Administrator to use the previously conducted performance test results to fulfill the one-time performance test requirement for HCN for each of the catalytic cracking units tested according to the requirements in paragraphs (a)(6)(i)(A) through (D) of this section.

(A) The request must include a copy of the complete source test report, the date(s) of the performance test and the test methods used. If available, you must also indicate whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode during the test, the control device configuration, including whether platinum or palladium combustion promoters were used during the test, and the CO concentration (measured using CO CEMS or manual test method) for each test run.

(B) You must submit a separate request for each catalytic cracking unit tested and you must submit each request to the Administrator no later than March 30, 2016.

(C) The Administrator will evaluate each request with respect to the completeness of the request, the completeness of the submitted test report and the appropriateness of the test methods used. The Administrator will notify the facility within 60 days of receipt of the request if it is approved or denied. If the Administrator fails to respond to the facility within 60 days of receipt of the request, the request will be automatically approved.

(D) If the request is approved, you do not need to conduct an additional HCN performance test. If the request is denied, you must conduct an additional HCN performance test following the requirements in (a)(6)(ii) of this section.

(ii) Unless you receive approval to use a previously conducted performance test to fulfill the one-time performance test requirement for HCN for your catalytic cracking unit as provided in paragraph (a)(6)(i) of this section, conduct a performance test for HCN for each catalytic cracking unit no later than August 1, 2017 according to following requirements:

(A) Select sampling port location, determine volumetric flow rate, conduct gas molecular weight analysis and measure moisture content as specified in either Item 1 of Table 4 of this subpart or Item 1 of Table 11 of this subpart.

(B) Measure HCN concentration using Method 320 of appendix A of this part. The method ASTM D6348-03 (Reapproved 2010) including Annexes A1 through A8 (incorporated by reference—see §63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part. The method ASTM D6348-12e1 (incorporated by reference—see §63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part with the following two caveats:

(1) The test plan preparation and implementation in the Annexes to ASTM D6348-03 (Reapproved 2010), Sections A1 through A8 are mandatory; and

(2) In ASTM D6348-03 (Reapproved 2010) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be $70\% \leq R \leq 130\%$. If the %R value does not meet this criterion for a target compound, the test data is not acceptable for that compound and the test must be repeated for that analyte (*i.e.*, the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation:

Reported Result = (Measured Concentration in the Stack \times 100 \div % R).

(C) Measure CO concentration as specified in either Item 2 or 3a of Table 11 of this subpart.

(D) Record and include in the test report an indication of whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode and the control device configuration, including whether platinum or palladium combustion promoters were used during the test.

(b) *What are the general requirements for performance test and performance evaluations? You must:*

(1) Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, you must operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. You must not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(3) Conduct each performance evaluation according to the requirements in §63.8(e).

(4) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of §63.1564, and determining the arithmetic average of the calculated emission rates.

(c) *What procedures must I use for an engineering assessment?* You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in paragraphs (c)(1) through (c)(4) of this section. Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority.

(1) You may use previous test results provided the tests are representative of current operating practices at the process unit, and provided EPA methods or approved alternatives were used;

(2) You may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) You may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or

(4) You may use design analysis based on engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(ii) Calculation of hourly average maximum flow rate based on physical equipment design such as pump or blower capacities; and

(iii) Calculation of TOC concentrations based on saturation conditions.

(d) *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of this section.

(1) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iii) in §63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows:

$$Ecat\text{-Limit} = \frac{13 \text{ g Ni/hr}}{NiEmR1_{st}} \times Ecat_{st} \quad (Eq. 1)$$

[View or download PDF](#)

Where:

$Ecat\text{-Limit}$ = Operating limit for equilibrium catalyst Ni concentration, mg/kg;

$NiEmR1_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each performance test run, g Ni/hr; and

$Ecat_{st}$ = Average equilibrium Ni concentration from laboratory test results, mg/kg.

(2) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iv) in §63.1564 (Ni per coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows:

$$Ecat\text{-Limit} = \frac{1.0 \text{ mg/kg coke burn-off}}{NiEmR2_{st}} \times Ecat_{st} \quad (Eq. 2)$$

[View or download PDF](#)

Where:

$NiEmR2_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of §63.1564 for each performance test run, mg/kg coke burn-off.

(3) If you choose to adjust the equilibrium catalyst Ni concentration to the maximum level, you can't adjust any other monitored operating parameter (i.e., gas flow rate, voltage, pressure drop, liquid-to-gas ratio).

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, total power and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

(e) *Can I change my operating limit?* You may change the established operating limit by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation.

(2) You must establish a revised operating limit for your continuous parameter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in paragraph (e)(1) of this section.

(3) You may change your site-specific opacity operating limit or Ni operating limit only by doing a new performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75276, Dec. 1, 2015]

[↑ Back to Top](#)

§63.1572 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.

(2) If you use a continuous emission monitoring system to meet the NSPS CO or SO₂ limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not

apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Data must be reduced as specified in §63.8(g)(2).

(b) You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.

(2) If you use a continuous opacity monitoring system to meet the NSPS opacity limit, you must conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(c) Except for flare monitoring systems, you must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section. For flares, on and after January 30, 2019, you must install, operate, calibrate, and maintain monitoring systems as specified in §§63.670 and 63.671. Prior to January 30, 2019, you must either meet the monitoring system requirements in paragraphs (c)(1) through (5) of this section or meet the requirements in §§63.670 and 63.671.

(1) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must also meet the equipment specifications in Table 41 of this subpart if pH strips or colorimetric tube sampling systems are used. You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must meet the requirements in Table 41 of this subpart for BLD systems. Alternatively, before August 1, 2017, you may install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately.

(2) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated, except for BLD systems.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day, except for BLD systems. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous, except for BLD systems.

(5) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(d) You must monitor and collect data according to the requirements in paragraphs (d)(1) and (2) of this section.

(1) You must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005; 80 FR 75277, Dec. 1, 2015]

[↑ Back to Top](#)

§63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. If you use this alternative, you shall use the same procedure for the performance test and for monitoring after the performance test. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator. Or, you may determine and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator using the appropriate control room instrumentation.

(ii) Install and operate a continuous parameter monitoring system to measure and record the temperature of the gases entering the control device (or exiting the catalyst regenerator if you do not use an add-on control device).

(iii) Calculate and record the hourly average actual exhaust gas flow rate using Equation 1 of this section as follows:

$$Q_{\text{gas}} = (1.12 \text{ scfm/dscfm}) \times (Q_{\text{air}} + Q_{\text{other}}) \times \left(\frac{\text{Temp}_{\text{gas}}}{293^{\circ}\text{K}} \right) \times \left(\frac{1 \text{ atm.}}{P_{\text{vent}}} \right) \quad (\text{Eq. 1})$$

[View or download PDF](#)

Where

Q_{gas} = Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

Q_{air} = Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

Q_{other} = Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of “other” gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

Temp_{gas} = Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

P_{vent} = Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the final atmospheric vent stack, you can assume $P_{\text{vent}} = 1 \text{ atm.}$

(2) You may use this alternative to calculating Q_{r} , the volumetric flow rate of exhaust gas for the catalytic cracking regenerator as required in Equation 1 of §63.1564, if you have a gas analyzer installed in the catalytic cracking regenerator exhaust vent prior to the addition of air or other gas streams. You may measure upstream or downstream of an electrostatic precipitator, but you shall measure upstream of a carbon monoxide boiler. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator. Or, you can determine and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator using the catalytic cracking unit control room instrumentation.

(ii) Install and operate a continuous gas analyzer to measure and record the concentration of carbon dioxide, carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust.

(iii) Calculate and record the hourly average flow rate using Equation 2 of this section as follows:

$$Q_r = \frac{79 \times Q_{air} + (100 - \%O_{xy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. 2})$$

[View or download PDF](#)

Where:

Q_r = Volumetric flow rate of exhaust gas from the catalyst regenerator before adding air or gas streams, dscm/min (dscf/min);

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis);

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator as determined from the catalytic cracking unit control room instrumentations, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis); and

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis).

(b) *What is the approved alternative for monitoring pressure drop?* You may use this alternative to a continuous parameter monitoring system for pressure drop if you operate a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. You shall:

(1) Conduct a daily check of the air or water pressure to the spray nozzles;

(2) Maintain records of the results of each daily check; and

(3) Repair or replace faulty (*e.g.*, leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading.

(c) *What is the approved alternative for monitoring pH or alkalinity levels?* You may use the alternative in paragraph (c)(1) or (2) of this section for a catalytic reforming unit.

(1) You shall measure and record the pH of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst

rejuvenation using pH strips as an alternative to a continuous parameter monitoring system. The pH strips must meet the requirements in Table 41 of this subpart.

(2) You shall measure and record the alkalinity of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using titration as an alternative to a continuous parameter monitoring system.

(d) *Can I use another type of monitoring system?* You may use an automated data compression system. An automated data compression system does not record monitored operating parameter values at a set frequency (e.g., once every hour) but records all values that meet set criteria for variation from previously recorded values. You must maintain a record of the description of the monitoring system and data recording system, including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all of the criteria in paragraphs (d)(1) through (5) of this section:

(1) The system measures the operating parameter value at least once every hour;

(2) The system records at least 24 values each day during periods of operation;

(3) The system records the date and time when monitors are turned off or on;

(4) The system recognizes unchanging data that may indicate the monitor is not functioning properly, alerts the operator, and records the incident; and

(5) The system computes daily average values of the monitored operating parameter based on recorded data.

(e) *Can I monitor other process or control device operating parameters?* You may request approval to monitor parameters other than those required in this subpart. You must request approval if:

(1) You use a control device other than a thermal incinerator, boiler, process heater, flare, electrostatic precipitator, or wet scrubber;

(2) You use a combustion control device (e.g., incinerator, flare, boiler or process heater with a design heat capacity of at least 44 MW, boiler or process heater where the vent stream is introduced into the flame zone), electrostatic precipitator, or scrubber but want to monitor a parameter other than those specified; or

(3) You wish to use another type of continuous emission monitoring system that provides direct measurement of a pollutant (i.e., a PM or multi-metals HAP continuous emission monitoring system, a carbonyl sulfide/carbon disulfide continuous emission monitoring system, a TOC continuous emission monitoring system, or HCl continuous emission monitoring system).

(f) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (f)(1) through (5) of this section.

(1) A description of each affected source and the parameter(s) to be monitored to determine whether the affected source will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(2) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine whether the affected source will continuously comply with the emission limitations and the schedule for this demonstration. You must certify that you will establish an operating limit for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(3) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. You also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(4) Supporting calculations.

(5) Averaging time for the alternative operating parameter.

(g) *How do I apply for alternative monitoring requirements if my catalytic cracking unit is equipped with a wet scrubber and I have approved alternative monitoring requirements under the new source performance standards for petroleum refineries?* (1) You may request alternative monitoring requirements according to the procedures in this paragraph if you meet each of the conditions in paragraphs (g)(1)(i) through (iii) of this section:

(i) Your fluid catalytic cracking unit regenerator vent is subject to the PM limit in 40 CFR 60.102(a)(1) and uses a wet scrubber for PM emissions control;

(ii) You have alternative monitoring requirements for the continuous opacity monitoring system requirement in 40 CFR 60.105(a)(1) approved by the Administrator; and

(iii) You are required by this subpart to install, operate, and maintain a continuous opacity monitoring system for the same catalytic cracking unit regenerator vent for which you have approved alternative monitoring requirements.

(2) You can request approval to use an alternative monitoring method prior to submitting your notification of compliance status, in your notification of compliance status, or at any time.

(3) You must submit a copy of the approved alternative monitoring requirements along with a monitoring plan that includes a description of the continuous monitoring system or method, including appropriate operating parameters that will be monitored, test results demonstrating compliance with the opacity limit used to establish an enforceable operating limit(s), and the

frequency of measuring and recording to establish continuous compliance. If applicable, you must also include operation and maintenance requirements for the continuous monitoring system.

(4) We will contact you within 30 days of receipt of your application to inform you of approval or of our intent to disapprove your request.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005; 80 FR 75277, Dec. 1, 2015]

[↑ Back to Top](#)

Notifications, Reports, and Records

[↑ Back to Top](#)

§63.1574 What notifications must I submit and when?

(a) Except as allowed in paragraphs (a)(1) through (3) of this section, you must submit all of the notifications in §§63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified.

(1) You must submit the notification of your intention to construct or reconstruct according to §63.9(b)(5) unless construction or reconstruction had commenced and initial startup had not occurred before April 11, 2002. In this case, you must submit the notification as soon as practicable before startup but no later than July 10, 2002. This deadline also applies to the application for approval of construction or reconstruction and approval of construction or reconstruction based on State preconstruction review required in §§63.5(d)(1)(i) and 63.5(f)(2).

(2) You must submit the notification of intent to conduct a performance test required in §63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days).

(3) If you are required to conduct an initial performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to §63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

(i) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status no later than 30 calendar days following completion of the initial compliance demonstration.

(ii) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for your affected source in §63.1563.

(b) As specified in §63.9(b)(2), if you startup your new affected source before April 11, 2002, you must submit the initial notification no later than August 9, 2002.

(c) If you startup your new or reconstructed affected source on or after April 11, 2002, you must submit the initial notification no later than 120 days after you become subject to this subpart.

(d) You also must include the information in Table 42 of this subpart in your notification of compliance status.

(e) If you request an extension of compliance for an existing catalytic cracking unit as allowed in §63.1563(c), you must submit a notification to your permitting authority containing the required information by October 13, 2003.

(f) As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each control system and continuous monitoring system for each affected source. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow.

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your permit under part 70 or 71 of this chapter, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan as submitted until the change is approved.

(2) Each plan must include, at a minimum, the information specified in paragraphs (f)(2)(i) through (xii) of this section.

(i) Process and control device parameters to be monitored for each affected source, along with established operating limits.

(ii) Procedures for monitoring emissions and process and control device operating parameters for each affected source.

(iii) Procedures that you will use to determine the coke burn-rate, the volumetric flow rate (if you use process data rather than direct measurement), and the rate of combustion of liquid or solid fossil fuels if you use an incinerator-waste heat boiler to burn the exhaust gases from a catalyst regenerator.

(iv) Procedures and analytical methods you will use to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.

(v) Procedures you will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if you use pH strips.

(vi) Procedures you will use to determine the HCl concentration of gases from a catalytic reforming unit when you use a colormetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment) and the sampling locations that will be used for compliance monitoring purposes.

(vii) Procedures you will use to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.

(viii) Monitoring schedule, including when you will monitor and when you will not monitor an affected source (e.g., during the coke burn-off, regeneration process).

(ix) Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system you use to meet an emission limit in this subpart. This plan must include procedures you will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

(x) Maintenance schedule for each monitoring system and control device for each affected source that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

(xi) If you use a fixed-bed gas-solid adsorption system to control emissions from a catalytic reforming unit, you must implement corrective action procedures if the HCl concentration measured at the selected compliance monitoring sampling location within the bed exceeds the operating limit. These procedures must require, at minimum, repeat measurement and recording of the HCl concentration in the adsorption system exhaust gases and at the selected compliance monitoring sampling location within the bed. If the HCl concentration at the selected compliance monitoring location within the bed is above the operating limit during the repeat measurement while the HCl concentration in the adsorption system exhaust gases remains below the operating limit, the adsorption bed must be replaced as soon as practicable. Your procedures must specify the sampling frequency that will be used to monitor the HCl concentration in the adsorption system exhaust gases subsequent to the repeat measurement and prior to replacement of the sorbent material (but not less frequent than once every 4 hours during coke burn-off). If the HCl concentration of the adsorption system exhaust gases is above the operating limit when measured at any time, the adsorption bed must be replaced within 24 hours or before the next regeneration cycle, whichever is longer.

(xii) Procedures that will be used for purging the catalyst if you do not use a control device to comply with the organic HAP emission limits for catalytic reforming units. These procedures will include, but are not limited to, specification of the minimum catalyst temperature and the minimum cumulative volume of gas per mass of catalyst used for purging prior to uncontrolled releases (i.e., during controlled purging events); the maximum purge gas temperature for uncontrolled purge events; and specification of the monitoring systems that will be used to monitor and record data during each purge event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6941, Feb. 9, 2005; 80 FR 75278, Dec. 1, 2015]

[↑ Back to Top](#)

§63.1575 What reports must I submit and when?

- (a) You must submit each report in Table 43 of this subpart that applies to you.
- (b) Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.
 - (1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.1563 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.
 - (2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.
 - (3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
 - (4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
 - (5) For each affected source that is subject to permitting regulations pursuant to part 70 or 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A) of this chapter, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.
- (c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.
 - (1) Company name and address.
 - (2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
 - (3) Date of report and beginning and ending dates of the reporting period.
 - (4) If there are no deviations from any emission limitation that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no

deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the semiannual compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period and identification of the sources for which there was a deviation.

(2) Information on the number, date, time, duration, and cause of deviations (including unknown cause, if applicable).

(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(4) The applicable operating limit or work practice standard from which you deviated and either the parameter monitor reading during the deviation or a description of how you deviated from the work practice standard.

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (c)(1) through (3) of this section, in paragraphs (d)(1) through (3) of this section, and in paragraphs (e)(2) through (13) of this section.

(1) [Reserved]

(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.

(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in §63.8(c)(8).

(4) An estimate of the quantity of each regulated pollutant emitted over the emission limit during the deviation, and a description of the method used to estimate the emissions.

(5) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) An identification of each HAP that was monitored at the affected source.

(10) A brief description of the process units.

(11) The monitoring equipment manufacturer(s) and model number(s).

(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.

(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

(f) You also must include the information required in paragraphs (f)(1) through (2) of this section in each compliance report, if applicable.

(1) You must include the information in paragraph (f)(1)(i) or (ii) of this section, if applicable.

(i) If you are complying with paragraph (k)(1) of this section, a summary of the results of any performance test done during the reporting period on any affected unit. Results of the performance test include the identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

(ii) If you are not complying with paragraph (k)(1) of this section, a copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual compliance report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief

process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (*e.g.*, you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your compliance report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

(g) You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information.

(h) [Reserved]

(i) If the applicable permitting authority has approved a period of planned maintenance for your catalytic cracking unit according to the requirements in paragraph (j) of this section, you must include the following information in your compliance report.

(1) In the compliance report due for the 6-month period before the routine planned maintenance is to begin, you must include a full copy of your written request to the applicable permitting authority and written approval received from the applicable permitting authority.

(2) In the compliance report due after the routine planned maintenance is complete, you must include a description of the planned routine maintenance that was performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance.

(j) If you own or operate multiple catalytic cracking units that are served by a single wet scrubber emission control device (*e.g.*, a Venturi scrubber), you may request the applicable permitting authority to approve a period of planned routine maintenance for the control device needed to meet requirements in your operation, maintenance, and monitoring plan. You must present data to the applicable permitting authority demonstrating that the period of planned maintenance results in overall emissions reductions. During this pre-approved time period, the emission control device may be taken out of service while maintenance is performed on the control device and/or one of the process units while the remaining process unit(s) continue to operate. During the period the emission control device is unable to operate, the emission limits, operating limits, and monitoring requirements applicable to the unit that is operating and the wet scrubber emission control device do not apply. The applicable permitting authority may require that you take specified actions to minimize emissions during the period of planned maintenance.

(1) You must submit a written request to the applicable permitting authority at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.

(2) Your written request must contain the information in paragraphs (j)(2)(i) through (v) of this section.

(i) A description of the planned routine maintenance to be performed during the next 6 months and why it is necessary.

(ii) The date the planned maintenance will begin and end.

(iii) A quantified estimate of the HAP and criteria pollutant emissions that will be emitted during the period of planned maintenance.

(iv) An analysis showing the emissions reductions resulting from the planned maintenance as opposed to delaying the maintenance until the next unit turnaround.

(v) Actions you will take to minimize emissions during the period of planned maintenance.

(k) *Electronic submittal of performance test and CEMS performance evaluation data.* For performance tests or CEMS performance evaluations conducted on and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, you must submit the results according to the procedures in paragraphs (k)(1) and (2) of this section.

(1) Within 60 days after the date of completing each performance test as required by this subpart, you must submit the results of the performance tests following the procedure specified in either paragraph (k)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (<http://www.epa.gov/ttn/chief/ert/index.html>) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage 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 (k)(1)(i).

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation required by §63.1571(a) and (b), you must submit the results of the performance evaluation following the procedure specified in either paragraph (k)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI is accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage 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 (k)(2)(i).

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75278, Dec. 1, 2015]

[↑ Back to Top](#)

§63.1576 What records must I keep, in what form, and for how long?

(a) You must keep the records specified in paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records specified in paragraphs (a)(2)(i) through (iv) of this section.

(i) Record the date, time, and duration of each startup and/or shutdown period, recording the periods when the affected source was subject to the standard applicable to startup and shutdown.

(ii) In the event that an affected unit fails to meet an applicable standard, record the number of failures. For each failure record the date, time and duration of each failure.

(iii) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, an estimate of the volume of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iv) Record actions taken to minimize emissions in accordance with §63.1570(c) and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in §63.10(b)(2)(viii).

(b) For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) The performance evaluation plan as described in §63.8(d)(2) for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you must keep previous (*i.e.*, superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under §63.8(d)(2).

(4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records in §63.6(h) for visible emission observations.

(d) You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you.

(e) You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan.

(f) You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater.

(g) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(h) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(i) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005; 80 FR 75279, Dec. 1, 2015]

[↑ Back to Top](#)

Other Requirements and Information

[↑ Back to Top](#)

§63.1577 What parts of the General Provisions apply to me?

Table 44 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

[↑ Back to Top](#)

§63.1578 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limitations and work practice standards in §§63.1564 through 63.1569 under §63.6(g).

(2) Approval of alternative opacity emission limitations in §§63.1564 through 63.1569 under §63.6(h)(9).

(3) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[↑ Back to Top](#)

§63.1579 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, the General Provisions of this part (§§63.1 through 63.15), and in this section as listed. If the same term is defined in subpart A of this part and in this section, it shall have the meaning given in this section for purposes of this subpart.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and equipment used for heat recovery.

Catalytic cracking unit catalyst regenerator means one or more regenerators (multiple regenerators) which comprise that portion of the catalytic cracking unit in which coke burn-off

and catalyst or contact material regeneration occurs and includes the regenerator combustion air blower(s).

Catalytic reforming unit means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis. The catalytic reforming unit includes the reactor, regenerator (if separate), separators, catalyst isolation and transport vessels (e.g., lock and lift hoppers), recirculation equipment, scrubbers, and other ancillary equipment.

Catalytic reforming unit regenerator means one or more regenerators which comprise that portion of the catalytic reforming unit and ancillary equipment in which the following regeneration steps typically are performed: depressurization, purge, coke burn-off, catalyst rejuvenation with a chloride (or other halogenated) compound(s), and a final purge. The catalytic reforming unit catalyst regeneration process can be done either as a semi-regenerative, cyclic, or continuous regeneration process.

Coke burn-off means the coke removed from the surface of the catalytic cracking unit catalyst or the catalytic reforming unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated using Equation 2 in §63.1564.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the destruction of organic HAP or VOC.

Combustion zone means the space in an enclosed combustion device (e.g., vapor incinerator, boiler, furnace, or process heater) occupied by the organic HAP and any supplemental fuel while burning. The combustion zone includes any flame that is visible or luminous as well as that space outside the flame envelope in which the organic HAP continues to be oxidized to form the combustion products.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminants from petroleum derivatives.

Continuous regeneration reforming means a catalytic reforming process characterized by continuous flow of catalyst material through a reactor where it mixes with feedstock, and a portion of the catalyst is continuously removed and sent to a special regenerator where it is regenerated and continuously recycled back to the reactor.

Control device means any equipment used for recovering, removing, or oxidizing HAP in either gaseous or solid form. Such equipment includes, but is not limited to, condensers, scrubbers, electrostatic precipitators, incinerators, flares, boilers, and process heaters.

Cyclic regeneration reforming means a catalytic reforming process characterized by continual batch regeneration of catalyst in situ in any one of several reactors (e.g., 4 or 5 separate reactors) that can be isolated from and returned to the reforming operation while maintaining continuous

reforming process operations (i.e., feedstock continues flowing through the remaining reactors without change in feed rate or product octane).

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; or
- (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.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in or through a line.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by the source, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

HCl means for the purposes of this subpart, gaseous emissions of hydrogen chloride that serve as a surrogate measure for total emissions of hydrogen chloride and chlorine as measured by Method 26 or 26A in appendix A to part 60 of this chapter or an approved alternative method.

Hot standby means periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit.

Incinerator means an enclosed combustion device that is used for destroying organic compounds, with or without heat recovery. Auxiliary fuel may be used to heat waste gas to combustion temperatures. An incinerator may use a catalytic combustion process where a substance is introduced into an exhaust stream to burn or oxidize contaminants while the substance itself remains intact, or a thermal process which uses elevated temperatures as a primary means to burn or oxidize contaminants.

Internal scrubbing system means a wet scrubbing, wet injection, or caustic injection control device that treats (in-situ) the catalytic reforming unit recirculating coke burn exhaust gases for acid (HCl) control during reforming catalyst regeneration upstream of the atmospheric coke burn vent.

Ni means, for the purposes of this subpart, particulate emissions of nickel that serve as a surrogate measure for total emissions of metal HAP, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Method 29 in appendix A to part 60 of this chapter or by an approved alternative method.

Nonmethane TOC means, for the purposes of this subpart, emissions of total organic compounds, excluding methane, that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25 in appendix A to part 60 of this chapter, by the combination of Methods 18 and 25A in appendix A to part 60 of this chapter, or by an approved alternative method.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to sulfur dioxide.

PM means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Methods 5, 5B or 5F in appendix A-3 to part 60 of this chapter or by an approved alternative method.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process vent means, for the purposes of this subpart, a gas stream that is continuously or periodically discharged during normal operation of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit, including gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device line prior to control or discharge to the atmosphere.

Reduced sulfur compounds means hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to hydrogen sulfide.

Responsible official means responsible official as defined in 40 CFR 70.2.

Semi-regenerative reforming means a catalytic reforming process characterized by shutdown of the entire reforming unit (e.g., which may employ three to four separate reactors) at specified intervals or at the owner's or operator's convenience for in situ catalyst regeneration.

Sulfur recovery unit means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide. This definition does not include a unit where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur, e.g., the LO-CAT II process.

TOC means, for the purposes of this subpart, emissions of total organic compounds that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25A in appendix A to part 60 of this chapter or by an approved alternative method.

TRS means, for the purposes of this subpart, emissions of total reduced sulfur compounds, expressed as an equivalent sulfur dioxide concentration, that serve as a surrogate measure of the total emissions of sulfide HAP carbonyl sulfide and carbon disulfide as measured by Method 15 in appendix A to part 60 of this chapter or by an approved alternative method.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005; 80 FR 75279, Dec. 1, 2015]

[↑ Back to Top](#)

Table 1 to Subpart UUU of Part 63—Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	You shall meet the following emission limits for each catalyst regenerator vent . . .
1. Subject to new source performance standard (NSPS) for PM in 40 CFR 60.102 and not electing §60.100(e)	PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or in supplemental liquid or solid fossil fuel, the incremental rate of PM emissions must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds

	per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or 40 CFR 60.102 and electing §60.100(e)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii)	PM emissions must not exceed 0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed the limits specified in Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off in the catalyst regenerator.
8. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Nickel (Ni) emissions must not exceed 13,000 milligrams per hour (mg/hr) (0.029 lb/hr).
9. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator.

[80 FR 75280, Dec. 1, 2015]

[↑ Back to Top](#)

Table 2 to Subpart UUU of Part 63—Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not elect §60.100(e)	Continuous opacity monitoring system	Any	On and after August 1, 2017, maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than 20 percent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i) or electing §60.100(e)	a. PM CEMS	Any	Not applicable.
	b. Continuous opacity monitoring system used to comply with a site-specific opacity limit	Cyclone or electrostatic precipitator	Maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test.
	c. Continuous parameter monitoring systems	Electrostatic precipitator	i. Maintain the daily average coke burn-off rate or daily average flow rate no higher than the limit established in the performance test.
			ii. Maintain the 3-hour rolling average total power and secondary current above the limit established in the performance test.
	d. Continuous parameter monitoring systems	Wet scrubber	i. Maintain the 3-hour rolling average liquid-to-gas ratio above the limit established in the performance test.
			ii. Except for periods of startup, shutdown, and hot standby, maintain the 3-hour rolling average pressure drop above the limit established in the performance test. ¹
	e. Bag leak detection (BLD) system	Fabric filter	Maintain particulate loading below the BLD alarm set point established in the initial adjustment of the BLD system or allowable seasonal

			adjustments.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii)	Any	Any	The applicable operating limits in Item 2 of this table.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Any	Any	See Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Any	Any	The applicable operating limits in Item 2.b, 2.c, 2.d, and 2.e of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM CEMS	Any	Not applicable.
7. Option 2: PM per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system used to comply with a site-specific opacity limit	Cyclone, fabric filter, or electrostatic precipitator	See Item 2.b of this table. Alternatively, before August 1, 2017, you may maintain the hourly average opacity of emissions from your catalyst generator vent no higher than the site-specific opacity limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) See item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current above the limit established in the performance test.
		ii. Wet scrubber	(1) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established in the performance test. (2) See Item 2.d.ii of the table.

			Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established in the performance test (not applicable to a wet scrubber of the non-venturi jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	Cyclone, fabric filter, or electrostatic precipitator	Maintain the 3-hour rolling average Ni operating value no higher than the limit established during the performance test. Alternatively, before August 1, 2017, you may maintain the daily average Ni operating value no higher than the limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(3) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the established during the performance test.
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test.
			(3) See Item 2.d.ii of this table.

			Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	Cyclone, fabric filter, or electrostatic precipitator	Maintain the 3-hour rolling average Ni operating value no higher than Ni operating limit established during the performance test. Alternatively, before August 1, 2017, you may elect to maintain the daily average Ni operating value no higher than the Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the limit established during the performance test.
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test.
			(3) See Item 2.d.ii of this table.

			Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.
10. During periods of startup, shutdown, or hot standby	Any	Any	Meet the requirements in §63.1564(a)(5).

¹If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in §63.1573(b), and comply with the daily inspections, recordkeeping, and repair provisions, instead of a continuous parameter monitoring system for pressure drop across the scrubber.

[80 FR 75280, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

[↑ Back to Top](#)

Table 3 to Subpart UUU of Part 63—Continuous Monitoring Systems for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	Any	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e); electing to meet the PM per coke burn-off limit	a. Cyclone b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent; or

		continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device, ¹ the voltage, current, and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, ² the coke burn-off rate or the gas flow rate entering or exiting the control device, ³ and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e); electing to meet the PM concentration limit	Any	Continuous emission monitoring system to measure and record the concentration of PM and oxygen from each catalyst regenerator vent.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM per coke burn-off limit	Any	The applicable continuous monitoring systems in item 2 of this table.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM concentration limit	Any	See item 3 of this table.
6. Option 1a: Elect NSPS subpart J, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	The applicable continuous monitoring systems in item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja, PM concentration limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	See item 3 of this table.
9. Option 2: PM per coke	Any	The applicable continuous monitoring systems

burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)		in item 2 of this table.
10. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device. ¹
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device ¹ ; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device ¹ and the voltage and current (to measure the total power to the system) and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, ² gas flow rate entering or exiting the control device, ¹ and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 10.a of this table.
11. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and the gas flow rate entering or exiting the control device. ¹
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and

		the gas flow rate entering or exiting the control device ¹ ; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device ¹ and voltage and current (to measure the total power to the system) and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, ² gas flow rate entering or exiting the control device, ¹ and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 11.a of this table.
12. Electing to comply with the operating limits in §63.1564(a)(5)(ii) during periods of startup, shutdown, or hot standby	Any	Continuous parameter monitoring system to measure and record the gas flow rate exiting the catalyst regenerator. ¹

¹If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate.

²If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in §63.1573(b) instead of a continuous parameter monitoring system for pressure drop across the scrubber.

[80 FR 75283, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

[↑ Back to Top](#)

Table 4 to Subpart UUU of Part 63—Requirements for Performance Tests for Metal HAP Emissions From Catalytic Cracking Units

As stated in §§63.1564(b)(2) and 63.1571(a)(5), you shall meet each requirement in the following table that applies to you.

For each new or	You must . . .	Using . . .	According to these
-----------------	----------------	-------------	--------------------

existing catalytic cracking unit catalyst regenerator vent . . .			requirements . . .
1. Any	a. Select sampling port's location and the number of traverse ports	Method 1 or 1A in appendix A-1 to part 60 of this chapter	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate	Method 2, 2A, 2C, 2D, or 2F in appendix A-1 to part 60 of this chapter, or Method 2G in appendix A-2 to part 60 of this chapter, as applicable	
	c. Conduct gas molecular weight analysis	Method 3, 3A, or 3B in appendix A-2 to part 60 of this chapter, as applicable	
	d. Measure moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter	
	e. If you use an electrostatic precipitator, record the total number of fields in the control system and how many operated during the applicable performance test		
	f. If you use a wet scrubber, record the total amount (rate) of water (or scrubbing liquid) and the amount (rate) of make-up liquid to the scrubber during		

	each test run		
2. Subject to the NSPS for PM in 40 CFR 60.102 and not elect §60.100(e)	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min)).
	b. Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off)	Equations 1, 2, and 3 of §63.1564 (if applicable)	
	c. Measure opacity of emissions	Continuous opacity monitoring system	You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test and reduce the data to 6-minute averages.
3. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect §60.100(e), electing the PM for coke burn-off limit	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).
	b. Compute coke burn-off rate and	Equations 1, 2, and 3 of §63.1564 (if applicable)	

	PM emission rate (lb/1,000 lb of coke burn-off)		
	c. Establish site-specific limit if you use a COMS	Continuous opacity monitoring system	If you elect to comply with the site-specific opacity limit in §63.1564(b)(4)(i), you must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test. For site specific opacity monitoring, reduce the data to 6-minute averages; determine and record the average opacity for each test run; and compute the site-specific opacity limit using Equation 4 of §63.1564.
4. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect §60.100(e)	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).
5. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 2 of this table.		
6. Option 1b: Elect NSPS subpart Ja requirements for PM	See item 3 of this table		

per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)			
7. Option 1c: Elect NSPS requirements for PM concentration, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 4 of this table		
8. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 3 of this table		
9. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Measure concentration of Ni b. Compute Ni emission rate (lb/hr)	Method 29 (40 CFR part 60, appendix A-8) Equation 5 of §63.1564	
	c. Determine the equilibrium catalyst Ni concentration	XRF procedure in appendix A to this subpart1; or EPA Method 6010B or 6020 or EPA Method 7520 or 7521 in SW-8462; or an alternative to the SW-846 method satisfactory to the Administrator	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit	i. Equations 6 and 7 of §63.1564 using data from continuous opacity monitoring system, gas flow rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run.

			(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
10. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	<p>a. Measure concentration of Ni.</p> <p>b. Compute Ni emission rate (lb/1,000 lb of coke burn-off)</p>	Method 29 (40 CFR part 60, appendix A-8). Equations 1 and 8 of §63.1564	
	c. Determine the equilibrium catalyst Ni concentration	See item 6.c. of this table	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit	i. Equations 9 and 10 of §63.1564 with data from continuous opacity monitoring system, coke burn-off rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run.
			(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow rate as near as practical to the continuous

			opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
	e. Record the catalyst addition rate for each test and schedule for the 10-day period prior to the test		
11. If you elect item 5 Option 1b in Table 1, item 7 Option 2 in Table 1, item 8 Option 3 in Table 1, or item 9 Option 4 in Table 1 of this subpart and you use continuous parameter monitoring systems	a. Establish each operating limit in Table 2 of this subpart that applies to you	Data from the continuous parameter monitoring systems and applicable performance test methods	
	b. Electrostatic precipitator or wet scrubber: Gas flow rate	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run.
			(2) You must determine and record the 3-hr average gas flow rate from the test runs. Alternatively, before August 1, 2017, you may determine and record the maximum hourly average gas flow rate from all the readings.
	c. Electrostatic precipitator: Total power (voltage and current) and secondary current	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect voltage, current, and secondary current monitoring data every 15 minutes during the entire period of the performance test; and determine and record the average voltage, current, and secondary current for each test run.

			Alternatively, before August 1, 2017, you may collect voltage and secondary current (or total power input) monitoring data every 15 minutes during the entire period of the initial performance test.
			(2) You must determine and record the 3-hr average total power to the system for the test runs and the 3-hr average secondary current from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average voltage and secondary current (or total power input) from all the readings.
	d. Electrostatic precipitator or wet scrubber: Equilibrium catalyst Ni concentration	Results of analysis for equilibrium catalyst Ni concentration	You must determine and record the average equilibrium catalyst Ni concentration for the 3 runs based on the laboratory results. You may adjust the value using Equation 1 or 2 of §63.1571 as applicable.
	e. Wet scrubber: Pressure drop (not applicable to non-venturi scrubber of jet ejector design)	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect pressure drop monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the average pressure drop for each test run. (2) You must determine and record the 3-hr average pressure drop from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average pressure drop from all the readings.

	f. Wet scrubber: Liquid-to-gas ratio	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect gas flow rate and total water (or scrubbing liquid) flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run; and determine the average total water (or scrubbing liquid) flow for each test run.
			(2) You must determine and record the hourly average liquid-to-gas ratio from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate from all the readings.
			(3) You must determine and record the 3-hr average liquid-to-gas ratio. Alternatively, before August 1, 2017, you may determine and record the minimum liquid-to-gas ratio.
	g. Alternative procedure for gas flow rate	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect air flow rate monitoring data or determine the air flow rate using control room instrumentation every 15 minutes during the entire period of the initial performance test.
			(2) You must determine and record the 3-hr average rate of all the readings from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average rate of all the readings.

		(3) You must determine and record the maximum gas flow rate using Equation 1 of §63.1573.
--	--	---

¹Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure).

²EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, and EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC.

[80 FR 75285, Dec. 1, 2015]

[↑ Back to Top](#)

Table 5 to Subpart UUU of Part 63—Initial Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your

	<p>heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ or 0.10 lb/million Btu of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period</p>	<p>vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in §63.1572.</p>
<p>2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e) and electing to meet the PM per coke burn-off limit</p>	<p>PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off</p>	<p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO₂, O₂, or CO monitor; or continuous opacity monitoring system meets the requirements in §63.1572.</p>
<p>3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit</p>	<p>PM emissions must not exceed 0.5 g/kg (0.5 lb PM/1,000 lb) of coke burn-off</p>	<p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance</p>

		<p>Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO₂, O₂, or CO monitor; or continuous opacity monitoring system meets the requirements in §63.1572.</p>
<p>4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit</p>	<p>If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air</p>	<p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in §63.1572.</p>
<p>5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit</p>	<p>If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air</p>	<p>You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.020 gr/dscf corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in §63.1572.</p>

<p>6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)</p>	<p>PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, PM emission must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period</p>	<p>The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. The average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. If you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.</p>
<p>7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)</p>	<p>PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off</p>	<p>The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. If you use a BLD; CO₂, O₂, CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.</p>
<p>8. Option 1c: Elect NSPS</p>	<p>PM emissions must not exceed</p>	<p>The average PM concentration,</p>

subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	0.040 gr/dscf corrected to 0 percent excess air	measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or Method 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is less than or equal to 0.040 gr/dscf corrected to 0 percent excess air. Your performance evaluation shows your PM CEMS meets the applicable requirements in §63.1572.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. If you use a BLD; CO ₂ , O ₂ , CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Nickel (Ni) emissions from your catalyst regenerator vent must not exceed 13,000 mg/hr (0.029 lb/hr)	The average Ni emission rate, measured using Method 29 (40 CFR part 60, appendix A-8) over the period of the initial performance test, is not more than 13,000 mg/hr (0.029 lb/hr). The Ni emission rate is calculated using Equation 5 of §63.1564; and if you use a BLD; CO ₂ , O ₂ , or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
11. Option 4: Ni per coke	Ni emissions from your catalyst	The average Ni emission rate,

burn-off limit not subject to the NSPS for PM	regenerator vent must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator	measured using Method 29 (40 CFR part 60, appendix A-8) over the period of the initial performance test, is not more than 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The Ni emission rate is calculated using Equation 8 of §63.1564; and if you use a BLD; CO ₂ , O ₂ , or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
---	---	---

[80 FR 75290, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

[↑ Back to Top](#)

Table 6 to Subpart UUU of Part 63—Continuous Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	a. PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10	i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator.

	lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period	
		ii. Conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.
		iii. Collecting the continuous opacity monitoring data for each catalyst regenerator vent according to §63.1572 and maintaining each 6-minute average at or below 30 percent, except that one 6-minute average during a 1-hour period can exceed 30 percent.
		iv. Before August 1, 2017, if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler; if applicable, maintaining the incremental rate of PM at or below 43 g/GJ (0.10 lb/million Btu) of heat input attributable to the solid or liquid fossil fuel.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test once every year.
3. Subject to NSPS for	PM emissions must not exceed	Determining and recording each

PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM per coke burn-off limit	0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off)	day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 0.5 g/kg (0.5 lb/1,000 lb) of coke burn-off; and conducting a performance test once every year.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit	If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air	Maintaining PM concentration below 0.040 gr/dscf corrected to 0 percent excess air.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit	If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air	Maintaining PM concentration below 0.020 gr/dscf corrected to 0 percent excess air.
6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 1 of this table	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	See item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air	See item 4 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	Determining and recording each day the average coke burn-off rate and the hours of operation and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data

		to determine the volumetric flow rate); maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 13,000 mg/hr (0.029 lb/hr)	Maintaining Ni emission rate below 13,000 mg/hr (0.029 lb/hr); and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.
11. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data to determine the volumetric flow rate); and maintaining Ni emission rate below 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.

[80 FR 75292, Dec. 1, 2015]

[↑ Back to Top](#)

Table 7 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	Continuous opacity monitoring system	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent	Collecting the continuous opacity monitoring data for each regenerator vent according to §63.1572 and maintain each 3-hour rolling average opacity of emissions no higher than 20 percent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1); or 40 CFR 60.102 and elect §60.100(e), electing to meet the PM per coke burn-off limit	a. Continuous opacity monitoring system, used for site-specific opacity limit—Cyclone or electrostatic precipitator	The average opacity must not exceed the opacity established during the performance test	Collecting the hourly and 3-hr rolling average opacity monitoring data according to §63.1572; maintaining the 3-hr rolling average opacity at or above the site-specific limit established during the performance test.
	b. Continuous parametric monitoring systems—electrostatic precipitator	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test	Collecting the hourly and daily average coke burn-off rate or average gas flow rate monitoring data according to §63.1572; and maintaining the daily average coke burn-off rate or average gas flow rate at or below the limit established during the performance test.
		ii. The average total power and secondary current to the control device must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to §63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test.
	c. Continuous parametric monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to §63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the

			3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to §63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test.
	d. BLD—fabric filter	Increases in relative particulate	Collecting and maintaining records of BLD system output; determining the cause of the alarm within 1 hour of the alarm; and alleviating the cause of the alarm within 3 hours by corrective action.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1), electing to meet the PM concentration limit	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4 or 5.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Continuous opacity monitoring system	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent	Collecting the 3-hr rolling average continuous opacity monitoring system data according to §63.1572; and maintaining the 3-hr rolling average opacity no higher than 20 percent.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test	Collecting the 3-hr rolling average continuous opacity monitoring system data according to §63.1572; maintaining the 3-hr rolling average opacity at or below the site-specific limit.

	b. Continuous parametric monitoring systems—electrostatic precipitator	See item 2.b of this table	See item 2.b of this table.
	c. Continuous parametric monitoring systems—wet scrubber	See item 2.c of this table	See item 2.c of this table.
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test	Collecting the hourly and 3-hr rolling average continuous opacity monitoring system data according to §63.1572; and maintaining the 3-hr rolling average opacity at or below the site-specific limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average continuous opacity monitoring system data according to §63.1572; and maintaining the hourly average opacity at or below the site-specific limit.
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average coke burn-off rate or average gas flow rate entering or exiting the control device must not exceed the operating limit established during the	Collecting the hourly and daily average coke burn-off rate or gas flow rate monitoring data according to §63.1572; and maintaining the daily coke burn-off rate or average gas flow rate at or

		performance test	below the limit established during the performance test.
		ii. The average total power (voltage and current) and secondary current to the control device must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to §63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average voltage and secondary current (or total power input) monitoring data according to §63.1572; and maintaining the daily average voltage and secondary current (or total power input) at or above the limit established during the performance test.
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to §63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the 3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average gas flow rate and water (or scrubbing liquid) flow rate monitoring data according to §63.1572 ¹ ; determining and recording the hourly average liquid-to-gas ratio; determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average

			liquid-to-gas ratio above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to §63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average pressure drop monitoring data according to §63.1572; and maintaining the daily average pressure drop above the limit established during the performance test.
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test	(1) Collecting the hourly average continuous opacity monitoring system data according to §63.1572; determining and recording equilibrium catalyst Ni concentration at least once a week ² ; collecting the hourly average gas flow rate monitoring data according to §63.1572 ¹ ; and determining and recording the hourly average Ni operating value using Equation 11 of §63.1564.
			(2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni

			operating limit established during the performance test. Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test	See item 7.b.i of this table.
		ii. The average total power (voltage and current) and secondary current must not fall below the level established in the performance test	See item 7.b.ii of this table.
		iii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week ² ; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot standby, the average	See item 7.c.ii of this table.

		pressure drop must not fall below the operating limit established in the performance test	
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week ² ; determining and recording the monthly rolling average of equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	d. BLD—fabric filter	i. Increases in relative particulate	See item 7.d of this table.
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week ² ; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test	(1) Collecting the hourly average continuous opacity monitoring system data according to §63.1572; collecting the hourly average coke burn rate and hourly average gas flow rate monitoring data according to §63.15721; determining and recording equilibrium catalyst Ni concentration at least once a week ² ; and determining and recording the hourly average

			Ni operating value using Equation 12 of §63.1564.
			(2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni operating limit established during the performance test Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average gas flow rate to the control device must not exceed the level established in the performance test	See item 7.b.i of this table.
		ii. The average voltage and secondary current (or total power input) must not fall below the level established in the performance test	See item 7.b.ii of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	See item 8.b.iii of this table.
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot	See item 7.c.ii of this table.

		standby, the daily average pressure drop must not fall below the operating limit established in the performance test	
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	See item 8.c.iii of this table.
	d. BLD—fabric filter	i. See item 2.d of this table	See item 2.d of this table.
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week ² ; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
10. During periods of startup, shutdown, or hot standby	Any control device, if elected	The inlet velocity limit to the primary internal cyclones of the catalytic cracking unit catalyst regenerator in §63.1564(a)(5)(ii)	Meeting the requirements in §63.1564(c)(5).

¹If applicable, you can use the alternative in §63.1573(a)(1) for gas flow rate instead of a continuous parameter monitoring system if you used the alternative method in the initial performance test.

²The equilibrium catalyst Ni concentration must be measured by the procedure, Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to this subpart; or by EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, or EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration; or by an alternative to EPA Method 6010B, 6020, 7520, or 7521 satisfactory to the Administrator. The EPA Methods 6010B, 6020, 7520, and 7521 are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA

Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[80 FR 75293, Dec. 1, 2015]

[↑ Back to Top](#)

Table 8 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	You shall meet the following emission limit for each catalyst regenerator vent . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	<p>a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).</p> <p>b. If you use a flare to meet the CO limit, then on and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the requirements for control devices in §63.11(b) and visible emissions must not exceed a total of 5 minutes during any 2 consecutive hours, or the flare must meet the requirements of §63.670.</p>

[80 FR 75299, Dec. 1, 2015]

[↑ Back to Top](#)

Table 9 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	Continuous emission monitoring system	Not applicable	Not applicable.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Continuous emission monitoring system.	Not applicable	Not applicable.
	b. Continuous parameter monitoring systems.	i. Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
		ii. Boiler or process heater with a design heat input capacity under 44 MW or a boiler or process heater in which all vent streams are not introduced into the flame zone.	Maintain the daily average combustion zone temperature above the limit established in the performance test.
		iii. Flare	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of §63.670.
3. During periods of startup, shutdown or hot	Any	Any	Meet the requirements in §63.1565(a)(5).

standby			
---------	--	--	--

[80 FR 75299, Dec. 1, 2015]

[↑ Back to Top](#)

Table 10 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	And you use this type of control device for your vent . . .	You shall install, operate, and maintain this type of continuous monitoring system . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	Not applicable	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Thermal incinerator	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature and oxygen content (percent, dry basis) in the incinerator vent stream.
	b. Process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone.	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature.
	c. Flare	On and after January 30, 2019, the monitoring systems required in §§63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence

		of a pilot flame, or the monitoring systems required in §§63.670 and 63.671.
	d. No control device	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in §63.1565(a)(5)(ii)	Any	Continuous parameter monitoring system to measure and record the concentration by volume (dry basis) of oxygen from each catalyst regenerator vent.

[80 FR 75300, Dec. 1, 2015]

[↑ Back to Top](#)

Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)

As stated in §63.1565(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Each new or existing catalytic cracking unit catalyst regenerator vent.	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in appendix A to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A to part 60 of this	

		chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.	
2. For each new or existing catalytic cracking unit catalyst regenerator vent if you use a continuous emission monitoring system.	Measure CO emissions	Data from your continuous emission monitoring system.	Collect CO monitoring data for each vent for 24 consecutive operating hours; and reduce the continuous emission monitoring data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
3. Each catalytic cracking unit catalyst regenerator vent if you use continuous parameter monitoring systems	a. Measure the CO concentration (dry basis) of emissions exiting the control device	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter, as applicable	
	b. Establish each operating limit in Table 9 of this subpart that applies to you	Data from the continuous parameter monitoring systems	
	c. Thermal incinerator combustion zone temperature	Data from the continuous parameter monitoring systems	Collect temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	d. Thermal incinerator: oxygen, content (percent, dry basis) in the incinerator vent stream	Data from the continuous parameter monitoring systems	Collect oxygen concentration (percent, dry basis) monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the

			minimum hourly average percent excess oxygen concentration from all the readings.
	e. If you use a process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone, establish operating limit for combustion zone temperature	Data from the continuous parameter monitoring systems	Collect the temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	f. If you use a flare, conduct visible emission observations	Method 22 (40 CFR part 60, appendix A-7)	On and after January 30, 2019, meet the requirements of §63.670. Prior to January 30, 2019, maintain a 2-hour observation period; and record the presence of a flame at the pilot light over the full period of the test or meet the requirements of §63.670.
	g. If you use a flare, determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6948, Feb. 9, 2005; 80 FR 75301, Dec. 1, 2015]

[↑ Back to Top](#)

Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4)	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis)	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance.
2. Not subject to the NSPS for CO in 40 CFR 60.103 60.102a(b)(4)	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis)	i. If you use a continuous parameter monitoring system, the average CO emissions measured by Method 10 over the period of the initial performance test are less than or equal to 500 ppmv (dry basis).
		ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in §63.1572.
	b. If you use a flare, visible emissions must not exceed a total of 5 minutes during any 2 operating hours	On and after January 30, 2019, the flare meets the requirements of §63.670. Prior to January 30, 2019, visible emissions, measured by Method 22 during the 2-hour observation period during the initial performance test, are no higher than 5 minutes, or the flare meets the requirements of §63.670.

[↑ Back to Top](#)

Table 13 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	If you must . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4)	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system	Collecting the hourly average CO monitoring data according to §63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Same as item 1.
	b. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous parameter monitoring system.	Maintaining the hourly average CO concentration below 500 ppmv (dry basis).
	c. Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour period.	Control device-flare	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, maintaining visible emissions below a total of 5 minutes during any 2-hour operating period, or meeting the requirements of §63.670.

[80 FR 75302, Dec. 1, 2015]

[↑ Back to Top](#)

Table 14 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), 60.102a(b)(4)	Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart, item 1.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Continuous emission monitoring system	Not applicable	Complying with Table 13 of this subpart, item 2.a.
	b. Continuous parameter monitoring systems—thermal incinerator.	i. The daily average combustion zone temperature must not fall below the level established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
		ii. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average oxygen concentration monitoring data according to §63.1572; and maintaining the daily average oxygen concentration above the limit established during the performance test.
	c. Continuous parameter monitoring systems—boiler or	The daily combustion zone temperature must not fall below the level established in the	Collecting the average hourly and daily temperature monitoring data according to

	process heater with a design heat input capacity under 44 MW or boiler or process heater in which all vent streams are not introduced into the flame zone.	performance test.	§63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
	d. Continuous parameter monitoring system—flare.	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, collecting the flare monitoring data according to §63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of §63.670.
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in §63.1565(a)(5)(ii).	Any control device	The oxygen concentration limit in §63.1565(a)(5)(ii)	Collecting the hourly average oxygen concentration monitoring data according to §63.1572 and maintaining the hourly average oxygen concentration at or above 1 volume percent (dry basis).

[80 FR 75303, Dec. 1, 2015]

[↑ Back to Top](#)

Table 15 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each applicable	You shall meet this emission limit during initial catalyst
---------------------	--

process vent for a new or existing catalytic reforming unit . . .	depressuring and catalyst purging operations . . .
1. Option 1	On and after January 30, 2019, vent emissions to a flare that meets the requirements of §63.670. Prior to January 30, 2019, vent emissions to a flare that meets the requirements for control devices in §63.11(b) and visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period, or vent emissions to a flare that meets the requirements of §63.670.
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. If you vent emissions to a boiler or process heater to comply with the percent reduction or concentration emission limitation, the vent stream must be introduced into the flame zone, or any other location that will achieve the percent reduction or concentration standard.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6951, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

[↑ Back to Top](#)

Table 16 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic reforming unit . . .	For this type of control device . . .	You shall meet this operating limit during initial catalyst depressuring and purging operations. . .
1. Option 1: Vent to flare	Flare	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of §63.670.
2. Option 2: Percent reduction or concentration	a. Thermal incinerator, boiler or process heater with a design heat input capacity under 44	The daily average combustion zone temperature must not fall below the limit established during the performance test.

limit	MW, or boiler or process heater in which all vent streams are not introduced into the flame zone	
	b. No control device	Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum catalyst purging conditions that must be met prior to allowing uncontrolled purge releases.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6951, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

[↑ Back to Top](#)

Table 17 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use this type of control device . . .	You shall install and operate this type of continuous monitoring system . . .
1. Option 1: Vent to a flare	Flare	On and after January 30, 2019, the monitoring systems required in §§63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§63.670 and 63.671.
2. Option 2: percent reduction or concentration limit.	Thermal incinerator, process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into the flame zone	Continuous parameter monitoring systems to measure and record the combustion zone temperature.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6952, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

[↑ Back to Top](#)

Table 18 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new or exiting catalytic reforming unit . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Vent to a flare	a. Conduct visible emission observations	Method 22 (40 CFR part 60, appendix A-7)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, 2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test, or the requirements of §63.670.
	b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.
2. Option 2: Percent reduction or concentration	a. Select sampling site	Method 1 or 1A (40 CFR part 60, appendix A). No traverse site selection method is needed for vents	Sampling sites must be located at the inlet (if you elect the emission reduction standard) and

limit		smaller than 0.10 meter in diameter.	outlet of the control device and prior to any releases to the atmosphere.
	b. Measure gas volumetric flow rate	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable	
	c. Measure TOC concentration (for percent reduction standard)	Method 25 (40 part 60, appendix A) to measure nonmethane TOC concentration (in carbon equivalents) at inlet and outlet of the control device. If the nonmethane TOC outlet concentration is expected to be less than 50 ppm (as carbon), you can use Method 25A to measure TOC concentration (as hexane) at the inlet and the outlet of the control device. If you use Method 25A, you may use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration to determine the nonmethane TOC concentration	Take either an integrated sample or four grab samples during each run. If you use a grab sampling technique, take the samples at approximately equal intervals in time, such as 15-minute intervals during the run.
	d. Calculate TOC or nonmethane TOC emission rate and mass emission reduction		Calculate emission rate by Equation 1 of §63.1566 (if you use Method 25) or Equation 2 of §63.1566 (if you use Method 25A). Calculate mass emission reduction by Equation 3 of §63.1566.
	e. For concentration standard, measure TOC concentration. (Optional: Measure methane concentration.)	Method 25A (40 CFR part 60, appendix A) to measure TOC concentration (as hexane) at the outlet of the control device. You may elect to use Method 18 (40 CFR part 60, appendix A)	

		to measure the methane concentration	
	f. Determine oxygen content in the gas stream at the outlet of the control device	Method 3A or 3B (40 CFR part 60, appendix A), as applicable	
	g. Calculate the TOC or nonmethane TOC concentration corrected for oxygen content (for concentration standard)	Equation 4 of §63.1566	
	h. Establish each operating limit in Table 16 of this subpart that applies to you for a thermal incinerator, or process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into flame zone	Data from the continuous parameter monitoring systems	Collect the temperature monitoring data every 15 minutes during the entire period of the initial TOC performance test. Determine and record the minimum hourly average combustion zone temperature.
	i. If you do not use a control device, document the purging conditions used prior to testing following the minimum requirements in the operation, maintenance, and monitoring plan.	Data from monitoring systems as identified in the operation, maintenance, and monitoring plan	Procedures in the operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6952, Feb. 9, 2005; 80 FR 75305, Dec. 1, 2015]

[↑ Back to Top](#)

Table 19 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(b)(7), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
Option 1	Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours	On and after January 30, 2019, the flare meets the requirements of §63.670. Prior to January 30, 2019, visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes, or the flare meets the requirements of §63.670.
Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent	The mass emission reduction of nonmethane TOC measured by Method 25 over the period of the performance test is at least 98 percent by weight as calculated using Equations 1 and 3 of §63.1566; or the mass emission reduction of TOC measured by Method 25A (or nonmethane TOC measured by Methods 25A and 18) over the period of the performance test is at least 98 percent by weight as calculated using Equations 2 and 3 of §63.1566; or the TOC concentration measured by Method 25A (or the nonmethane TOC concentration measured by Methods 25A and 18) over the period of the performance test does not exceed 20 ppmv (dry basis as hexane) corrected to 3 percent oxygen as calculated using Equation 4 of §63.1566.

[70 FR 6953, Feb. 9, 2005, as amended at 80 FR 75305, Dec. 1, 2015]

[↑ Back to Top](#)

Table 20 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For this emission limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . .
1. Option 1	Vent emissions from your process vent to a flare	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours, or meeting the requirements of §63.670.
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.	Maintaining a 98 percent by weight emission reduction of TOC or nonmethane TOC; or maintaining a TOC or nonmethane TOC concentration of not more than 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75305, Dec. 1, 2015]

[↑ Back to Top](#)

Table 21 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by . . .
---	-------------------------	---------------------------------------	---

reforming unit ...			
1. Option 1	Flare	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, collecting flare monitoring data according to §63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of §63.670.
2. Option 2	a. Thermal incinerator boiler or process heater with a design input capacity under 44 MW or boiler or process heater in which not all vent streams are not introduced into the flame zone	Maintain the daily average combustion zone temperature above the limit established during the performance test	Collecting, the hourly and daily temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
	b. No control device	Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum purging conditions that must be met prior to allowing uncontrolled purge releases	Recording information to document compliance with the procedures in your operation, maintenance, and monitoring plan.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

[↑ Back to Top](#)

Table 22 to Subpart UUU of Part 63—Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn-off and catalyst rejuvenation . . .
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of hydrogen chloride (HCl) by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.

[70 FR 6955, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

[↑ Back to Top](#)

Table 23 to Subpart UUU of Part 63—Operating Limits for Inorganic HAP Emission Limitations for Catalytic Reforming Units

As stated in §63.1567(a)(2), you shall meet each operating limit in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit with this type of control device . . .	You shall meet this operating limit during coke burn-off and catalyst rejuvenation . . .
1. Wet scrubber	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
2. Internal scrubbing system or no control device (<i>e.g.</i> , hot regen system) meeting outlet HCl concentration limit.	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test.
3. Internal scrubbing system meeting HCl percent reduction standard.	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit

	established during the performance test.
4. Fixed-bed gas-solid adsorption system	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the HCl concentration in the adsorption system exhaust gas must not exceed the limit established during the performance test.
5. Moving-bed gas-solid adsorption system (<i>e.g.</i> , Chlorsorb™ System).	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System); and the weekly average chloride level on the sorbent leaving the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™ System).

[70 FR 6955, Feb. 9, 2005]

[↑ Back to Top](#)

Table 24 to Subpart UUU of Part 63—Continuous Monitoring Systems for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(1), you shall meet each requirement in the following table that applies to you.

If you use this type of control device for your vent .	You shall install and operate this type of continuous monitoring system . . .
1. Wet scrubber	Continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the scrubber during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record gas flow rate entering or exiting the scrubber during coke burn-off and catalyst rejuvenation ¹ ; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation. ²
2. Internal scrubbing system or no control device (<i>e.g.</i> , hot regen system) to meet HCl outlet concentration limit	Colormetric tube sampling system to measure the HCl concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.

3. Internal scrubbing system to meet HCl percent reduction standard	Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation. ²
4. Fixed-bed gas-solid adsorption system	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation; and colorimetric tube sampling system to measure the gaseous HCl concentration in the adsorption system exhaust and at a point within the absorbent bed not to exceed 90 percent of the total length of the absorbent bed during coke burn-off and catalyst rejuvenation. The colorimetric tube sampling system must meet the requirements in Table 41 of this subpart.
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System).	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation.

¹If applicable, you can use the alternative in §63.1573 (a)(1) instead of a continuous parameter monitoring system for gas flow rate or instead of a continuous parameter monitoring system for the cumulative volume of gas.

²If applicable, you can use the alternative in §63.1573(c)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in §63.1573(c)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).

[70 FR 6956, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

[↑ Back to Top](#)

Table 25 to Subpart UUU of Part 63—Requirements for Performance Tests for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
1. Any or no control system	a. Select sampling port location(s) and the number of traverse points	Method 1 or 1A (40 CFR part 60, appendix A), as applicable.	(1) If you operate a control device and you elect to meet an applicable HCl percent reduction standard, sampling sites must be located at the inlet of the control device or internal scrubbing system and at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series.
			(2) If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable.	
	c. Conduct gas	Method 3, 3A, or 3B (40	

	molecular weight analysis.	CFR part 60, appendix A), as applicable	
	d. Measure moisture content of the stack gas	Method 4 (40 CFR part 60, appendix A)	
	e. Measure the HCl concentration at the selected sampling locations	Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A	(1) For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi-regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up.
			(2) Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of §63.1567) for each sampling location for each test run.
			(3) Determine and record the percent emission reduction, if applicable, using Equation 3 of §63.1567 for each test run.
			(4) Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values.
2. Wet scrubber	a. Establish operating limit for pH level or	i. Data from continuous parameter monitoring systems	Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting

	alkalinity		scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH procedure in §63.1573(b)(1)	Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(c)(2)	Measure and record the alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
	b. Establish operating limit for liquid-to-gas ratio.	i. Data from continuous parameter monitoring systems	Measure and record the gas flow rate entering or exiting the scrubber and the total water (or scrubbing liquid) flow rate entering the scrubber every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum

			liquid-to-gas ratio from the recorded, paired values.
		ii. Alternative procedure for gas flow rate in §63.1573(a)(1)	Collect air flow rate monitoring data or determine the air flow rate using control room instruments every 15 minutes during the entire period of the initial performance test. Determine and record the hourly average rate of all the readings. Determine and record the maximum gas flow rate using Equation 1 of §63.1573.
3. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl outlet concentration limit.	Establish operating limit for HCl concentration.	Data from continuous parameter monitoring system.	Measure and record the HCl concentration in the catalyst regenerator exhaust gas using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. Determine and record the operating limit for HCl concentration using Equation 4 of §63.1567.
4. Internal scrubbing system meeting HCl percent reduction standard	a. Establish operating limit for pH level or alkalinity	i. Data from continuous parameter monitoring system	Measure and record the pH alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH method in	Measure and in record pH of

		§63.1573(c)(1)	the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(c)(2)	Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
	b. Establish operating limit for liquid-to-gas ratio	Data from continuous parameter monitoring systems	Measure and record the gas entering or exiting the internal scrubbing system and the total water (or scrubbing liquid) flow rate entering the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.
5. Fixed-bed gas-solid adsorption system. Gas-solid	a. Establish operating limit for temperature	Data from continuous parameter monitoring system	Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes.

			Determine and record the maximum hourly average temperature.
	b. Establish operating limit for HCl concentration	i. Data from continuous parameter monitoring systems	(1) Measure and record the HCl concentration in the exhaust gas from the fixed-bed adsorption system using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages.
			(2) If you elect to comply with the HCl outlet concentration limit (Option 2), determine and record the operating limit for HCl concentration using Equation 4 of §63.1567. If you elect to comply with the HCl percent reduction standard (Option 1), determine and record the operating limit for HCl concentration using Equation 5 of §63.1567.
6. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System)	a. Establish operating limit for temperature	Data from continuous parameter monitoring systems.	Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature.
	b. Measure the chloride level on the sorbent entering and exiting the adsorption system.	Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to subpart UUU; or EPA Method 5050 combined either with EPA	Measure and record the chloride concentration of the sorbent material entering and exiting the adsorption system at least three times during each test run. Determine and record the average weight

		Method 9056, or with EPA Method 9253; or EPA Method 9212 with the soil extraction procedures listed within the method. ¹	percent chloride concentration of the sorbent entering the adsorption system for each test run. Determine and record the average weight percent chloride concentration of the sorbent exiting the adsorption system for each test run.
--	--	---	--

¹The EPA Methods 5050, 9056, 9212 and 9253 are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[70 FR 6956, Feb. 9, 2005, as amended at 80 FR 75307, Dec. 1, 2015]

[↑ Back to Top](#)

Table 26 to Subpart UUU of Part 63—Initial Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(b)(4), you shall meet each requirement in the following table that applies to you.

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv, (dry basis), corrected to 3 percent oxygen.	Average emissions HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 92 percent or to a concentration less than or equal to 30 ppmv (dry basis) corrected to 3 percent oxygen.
2. Each existing cyclic or	Reduce uncontrolled	Average emissions of HCl measured

continuous catalytic reforming unit and each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 97 percent or to a concentration less than or equal to 10 ppmv (dry basis) corrected to 3 percent oxygen.
---	--	--

[70 FR 6959, Feb. 9, 2005]

[↑ Back to Top](#)

Table 27 to Subpart UUU of Part 63—Continuous Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 92 percent HCl emission reduction or an HCl concentration no more than 30 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.

[70 FR 6960, Feb. 9, 2005]

[↑ Back to Top](#)

Table 28 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using this type of control device or system . . .	For this operating limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
1. Wet scrubber	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the level established during the performance test	Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572 ¹ ; and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test	Collecting the hourly average gas flow rate ² and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
2. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl concentration limit	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test	Measuring and recording the HCl concentration at least 4 times during a regeneration cycle (equally spaced in time) or every 4 hours, whichever is more frequent, using a colorimetric tube sampling system; calculating the daily average HCl concentration as an arithmetic average of all samples collected in each 24-hour period from the start of the coke burn-off cycle or for the entire duration of the coke burn-off cycle if the coke burn-off cycle is less than 24 hours; and maintaining the daily average HCl concentration below the applicable operating limit.

3. Internal scrubbing system meeting percent HCl reduction standard	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test	Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572 ¹ and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test	Collecting the hourly average gas flow rate ² and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
4. Fixed-bed gas-solid adsorption systems	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.
	b. The HCl concentration in the exhaust gas from the fixed-bed gas-solid adsorption system must not exceed the limit established during the performance test	Measuring and recording the concentration of HCl weekly or during each regeneration cycle, whichever is less frequent, using a colormetric tube sampling system at a point within the adsorbent bed not to exceed 90 percent of the total length of the adsorption bed during coke-burn-off and catalyst rejuvenation; implementing procedures in the operating and maintenance plan if the HCl concentration at the sampling location within the adsorption bed exceeds the operating limit; and maintaining the HCl concentration in the gas from the adsorption system below the applicable operating limit.
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System)	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.

	b. The weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System)	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride ³ ; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™ System).
	c. The weekly average chloride level on the sorbent exiting the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™ System)	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride concentration; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.8 weight percent Chlorsorb™ System).

¹If applicable, you can use either alternative in §63.1573(c) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test.

²If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for the gas flow rate or cumulative volume of gas entering or exiting the system if you used the alternative method in the initial performance test.

³The total chloride concentration of the sorbent material must be measured by the procedure, “Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)” in appendix A to this subpart; or by using EPA Method 5050, Bomb Preparation Method for Solid Waste, combined either with EPA Method 9056, Determination of Inorganic Anions by Ion Chromatography, or with EPA Method 9253, Chloride (Titrimetric, Silver Nitrate); or by using EPA Method 9212, Potentiometric Determination of Chloride in Aqueous Samples with Ion-Selective Electrode, and using the soil extraction procedures listed within the method. The EPA Methods 5050, 9056, 9212 and 9253 are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at <http://www.epa.gov/epaoswer/hazwaste/test/main.htm>.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75308, Dec. 1, 2015]

[↑ Back to Top](#)

Table 29 to Subpart UUU of Part 63—HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	You shall meet this emission limit for each process vent . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 long tons per day (LTD) and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of sulfur dioxide (SO ₂) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO ₂ concentration (dry basis) at zero percent oxygen.

[80 FR 75309, Dec. 1, 2015]

[↑ Back to Top](#)

Table 30 to Subpart UUU of Part 63—Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

For . . .	If use this type of control device . . .	You shall meet this operating limit . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.
3. Option 2: TRS limit, if using continuous emissions monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.
4. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
5. Startup or shutdown option 1: Electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	Flare	On and after January 30, 2019, meet the applicable requirements of §63.670. Prior to January 30, 2019, meet the applicable requirements of either §63.11(b) or §63.670.
6. Startup or shutdown option 2: Electing	Thermal	Maintain the hourly average

to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during startup or shutdown events	incinerator or thermal oxidizer	combustion zone temperature at or above 1,200 degrees Fahrenheit and maintain the hourly average oxygen concentration in the exhaust gas stream at or above 2 volume percent (dry basis).
---	---------------------------------	---

[80 FR 75310, Dec. 1, 2015]

[↑ Back to Top](#)

Table 31 to Subpart UUU of Part 63—Continuous Monitoring Systems for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration	Continuous emission monitoring system to measure and record the hourly average concentration of SO ₂ (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen (O ₂) emissions. Calculate the reduced sulfur emissions as SO ₂ (dry basis) at zero percent excess air. <i>Exception:</i> You can use an instrument having an air or SO ₂ dilution and oxidation system to convert the reduced sulfur to SO ₂ for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of

		the resultant SO ₂ instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit	<p>i. Complete either item 1.a or item 1.b; and</p> <p>ii. Either a continuous emission monitoring system to measure and record the O₂ concentration for the inlet air/oxygen supplied to the system or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.</p>
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air if you use an oxidation or reduction control system followed by incineration	Continuous emission monitoring system to measure and record the hourly average concentration of SO ₂ (dry basis), at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and O ₂ emissions for each exhaust stack. Calculate the reduced sulfur emissions as SO ₂ (dry basis), at zero percent excess air. <i>Exception:</i> You can use an instrument having an air or O ₂ dilution and oxidation system to convert the reduced sulfur to SO ₂ for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO ₂ instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR	i. Complete either item 2.a or item 2.b; and

	60.102a(f)(1)(i) to set your emission limit	ii. Either a continuous emission monitoring system to measure and record the O ₂ concentration for the inlet air/oxygen supplied to the system, or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO ₂ concentration (dry basis) at zero percent oxygen	i. Continuous emission monitoring system to measure and record the hourly average concentration of TRS for each exhaust stack; this monitor must include an oxygen monitor for correcting the data for excess oxygen; or
		ii. Continuous parameter monitoring systems to measure and record the combustion zone temperature of each thermal incinerator and the oxygen content (percent, dry basis) in the vent stream of the incinerator.
4. Startup or shutdown option 1: electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	On and after January 30, 2019, monitoring systems as specified in §§63.670 and 63.671. Prior to January 30, 2019, either continuous parameter monitoring systems following the requirements in §63.11 (to detect the presence of a flame; to measure and record the net heating value of the gas being combusted; and to measure and record the volumetric flow of the gas being combusted) or monitoring systems as specified in §§63.670 and 63.671.
5. Startup or shutdown option 2: electing to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	Continuous parameter monitoring systems to measure and record the firebox temperature of each thermal incinerator or oxidizer and the oxygen content (percent, dry basis) in the exhaust vent from the incinerator or oxidizer.

[↑ Back to Top](#)

Table 32 to Subpart UUU of Part 63—Requirements for Performance Tests for HAP Emissions From Sulfur Recovery Units Not Subject to the New Source Performance Standards for Sulfur Oxides

As stated in §63.1568(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Elect NSPS. Each new and existing sulfur recovery unit	a. Measure SO ₂ concentration (for an oxidation or reduction system followed by incineration) or measure the concentration of reduced sulfur (or SO ₂ if you use an instrument to convert the reduced sulfur to SO ₂) for a reduction control system without incineration	Data from continuous emission monitoring system	Collect SO ₂ monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
	b. Measure O ₂ concentration for the inlet air/oxygen supplied to the system, if using Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit. You may use either an O ₂ CEMS method in item 1.b.i of this table or the flow monitor in item 1.b.ii of this table	i. Data from continuous emission monitoring system; or	Collect O ₂ monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period; and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
		ii. Data from flow monitor for ambient air and purchased oxygen-enriched gas	Collect gas flow rate monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from 4 or more data points equally spaced

			over each 1-hour period; calculate the hourly O ₂ percent using Equation 10 of 40 CFR 60.106a(a)(6)(iv); and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
2. Option 2: TRS limit, using CEMS. Each new and existing sulfur recovery unit	Measure the concentration of reduced sulfur (or SO ₂ if you use an instrument to convert the reduced sulfur to SO ₂)	Data from continuous emission monitoring system	Collect TRS data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
3. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new and existing sulfur recovery unit	a. Select sampling port's location and the number of traverse ports	Method 1 or 1A in Appendix A-1 to part 60 of this chapter	Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate	Method 2, 2A, 2C, 2D, or 2F in appendix A-1 to part 60 of this chapter, or Method 2G in appendix A-2 to part 60 of this chapter, as applicable	
	c. Conduct gas molecular weight analysis; obtain the oxygen concentration needed to correct the emission rate for excess air	Method 3, 3A, or 3B in appendix A-2 to part 60 of this chapter, as applicable	Take the samples simultaneously with reduced sulfur or moisture samples.
	d. Measure moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter	Make your sampling time for each Method 4 sample equal to that for 4 Method 15 samples.
	e. Measure the	Method 15 or	If the cross-sectional area of the

	concentration of TRS	15A in appendix A-5 to part 60 of this chapter, as applicable	duct is less than 5 square meters (m ²) or 54 square feet, you must use the centroid of the cross section as the sampling point. If the cross-sectional area is 5 m ² or more and the centroid is more than 1 meter (m) from the wall, your sampling point may be at a point no closer to the walls than 1 m or 39 inches. Your sampling rate must be at least 3 liters per minute or 0.10 cubic feet per minute to ensure minimum residence time for the sample inside the sample lines.
	f. Calculate the SO ₂ equivalent for each run after correcting for moisture and oxygen	The arithmetic average of the SO ₂ equivalent for each sample during the run	
	g. Correct the reduced sulfur samples to zero percent excess air	Equation 1 of §63.1568	
	h. Establish each operating limit in Table 30 of this subpart that applies to you	Data from the continuous parameter monitoring system	
	i. Measure thermal incinerator: combustion zone temperature	Data from the continuous parameter monitoring system	Collect temperature monitoring data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average temperature from all the readings.
	j. Measure thermal incinerator: oxygen concentration (percent, dry basis) in the vent stream	Data from the continuous parameter monitoring system	Collect oxygen concentration (percent, dry basis) data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average percent excess oxygen concentration.

[↑ Back to Top](#)

Table 33 to Subpart UUU of Part 63—Initial Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to NSPS: Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) SO ₂ at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of SO ₂ emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO ₂ limit. You are not required to do another performance test to demonstrate initial compliance.
		You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average

	concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO ₂ limit. You are not required to do another performance test to demonstrate initial compliance.
		You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	Each 12-hour rolling average concentration of SO ₂ emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the monitoring system meets the applicable requirements in §63.1572.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or concentration determined	Each 12-hour rolling average concentration of reduced sulfur compounds measured by the continuous emission monitoring system during the initial

	using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	performance test is less than or equal to 300 ppmv, calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of TRS compounds expressed as an equivalent SO ₂ concentration (dry basis) at zero percent oxygen	If you use continuous parameter monitoring systems, the average concentration of TRS emissions measured using Method 15 during the initial performance test is less than or equal to 300 ppmv expressed as equivalent SO ₂ concentration (dry basis) at zero percent oxygen. If you use a continuous emission monitoring system, each 12-hour rolling average concentration of TRS emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv expressed as an equivalent SO ₂ (dry basis) at zero percent oxygen; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572.

[80 FR 75313, Dec. 1, 2015]

[↑ Back to Top](#)

Table 34 to Subpart UUU of Part 63—Continuous Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	Collecting the hourly average SO ₂ monitoring data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O ₂ concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of SO ₂ ; maintaining each 12-hour rolling average concentration of SO ₂ at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO ₂ greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	Collecting the hourly average reduced sulfur (and air or O ₂ dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O ₂ concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the	a. 250 ppmv (dry basis) of SO ₂ at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an	Collecting the hourly average SO ₂ data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O ₂ concentration or flow

NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	oxidation or reduction control system followed by incineration	monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of SO ₂ ; maintaining each 12-hour rolling average concentration of SO ₂ at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO ₂ greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	Collecting the hourly average reduced sulfur (and air or O ₂ dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O ₂ concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of TRS compounds, expressed as an SO ₂ concentration (dry basis) at zero percent oxygen or reduced sulfur compounds calculated as ppmv SO ₂ (dry basis) at zero percent excess air	i. If you use continuous parameter monitoring systems, collecting the hourly average TRS monitoring data according to §63.1572 and maintaining each 12-hour average concentration of TRS at or below the applicable emission limitation; or
		ii. If you use a continuous emission monitoring system, collecting the hourly average TRS monitoring data according to §63.1572, determining

		and recording each 12-hour rolling average concentration of TRS; maintaining each 12-hour rolling average concentration of TRS at or below the applicable emission limitation; and reporting any 12-hour rolling average TRS concentration greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
--	--	--

[80 FR 75315, Dec. 1, 2015]

[↑ Back to Top](#)

Table 35 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Meeting the requirements of Table 34 of this subpart.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Meeting the requirements of Table 34 of this subpart.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides	a. Maintain the daily average combustion zone temperature above the level established during	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average

in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	the performance test	combustion zone temperature at or above the limit established during the performance test
	b. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average O ₂ monitoring data according to §63.1572; and maintaining the average O ₂ concentration above the level established during the performance test.
4. Startup or shutdown option 1: Electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	Using a flare meeting the requirements in §63.11(b) or §63.670	On and after January 30, 2019, complying with the applicable requirements of §63.670. Prior to January 30, 2019, complying with the applicable requirements of either §63.11(b) or §63.670.
5. Startup or shutdown option 2: Electing to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	a. Minimum hourly average temperature of 1,200 degrees Fahrenheit	Collecting continuous (at least once every 15 minutes) and hourly average temperature monitoring data according to §63.1572; and maintaining the daily average firebox temperature at or above 1,200 degrees Fahrenheit.
	b. Minimum hourly average outlet oxygen concentration of 2 volume percent (dry basis)	Collecting continuous (at least once every 15 minutes) and hourly average O ₂ monitoring data according to §63.1572; and maintaining the average O ₂ concentration at or above 2 volume percent (dry basis).

[80 FR 75316, Dec. 1, 2015]

[↑ Back to Top](#)

Table 36 to Subpart UUU of Part 63—Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(a)(1), you shall meet each work practice standard in the following table that applies to you.

Option	You shall meet one of these equipment standards . . .
1. Option 1	Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.
2. Option 2	Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device.
3. Option 3	Seal the bypass line by installing a solid blind between piping flanges.
4. Option 4	Vent the bypass line to a control device that meets the appropriate requirements in this subpart.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6964, Feb. 9, 2005]

[↑ Back to Top](#)

Table 37 to Subpart UUU of Part 63—Requirements for Performance Tests for Bypass Lines

As stated in §63.1569(b)(1), you shall meet each requirement in the following table that applies to you.

For this standard . . .	You shall . . .
1. Option 1: Install and operate a flow indicator, level recorder, or electronic valve position monitor.	Record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

[↑ Back to Top](#)

Table 38 to Subpart UUU of Part 63—Initial Compliance With Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(b)(2), you shall meet each requirement in the following table that applies to you.

Option . . .	For this work practice standard . . .	You have demonstrated initial compliance if . . .
1. Each new or existing bypass line associated with a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit	a. Option 1: Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere	The installed equipment operates properly during each run of the performance test and no flow is present in the line during the test.
	b. Option 2: Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device	As part of the notification of compliance status, you certify that you installed the equipment, the equipment was operational by your compliance date, and you identify what equipment was installed.
	c. Option 3: Seal the bypass line by installing a solid blind between piping flanges	See item 1.b of this table.
	d. Option 4: Vent the bypass line to a control device that meets the appropriate requirements in this subpart	See item 1.b of this table.

[70 FR 6965, Feb. 9, 2005]

[↑ Back to Top](#)

Table 39 to Subpart UUU of Part 63—Continuous Compliance With Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(c)(1), you shall meet each requirement in the following table that applies to you.

If you elect this standard . . .	You shall demonstrate continuous compliance by . . .
---	---

1. Option 1: Flow indicator, level recorder, or electronic valve position monitor.	Monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line.
2. Option 2: Car-seal or lock-and-key device	Visually inspecting the seal or closure mechanism at least once every month; and recording whether the bypass line valve is maintained in the closed position and whether flow is present in the line.
3. Option 3: Solid blind flange	Visually inspecting the blind at least once a month; and recording whether the blind is maintained in the correct position such that the vent stream cannot be diverted through the bypass line.
4. Option 4: Vent to control device	Monitoring the control device according to appropriate subpart requirements.
5. Option 1, 2, 3, or 4	Recording and reporting the time and duration of any bypass.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6965, Feb. 9, 2005]

[↑ Back to Top](#)

Table 40 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Opacity Monitoring Systems and Continuous Emission Monitoring Systems

As stated in §63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
1. Continuous opacity monitoring system	Performance specification 1 (40 CFR part 60, appendix B).
2. PM CEMS; this monitor must include an O ₂ monitor for correcting the data for excess air	The requirements in 40 CFR 60.105a(d).
3. CO continuous emission monitoring system	Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
4. CO continuous emission monitoring	Performance specification 4 (40 CFR part 60,

system used to demonstrate emissions average under 50 ppm (dry basis)	appendix B); and span value of 100 ppm.
5. SO ₂ continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must include an O ₂ monitor for correcting the data for excess air	Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm SO ₂ , or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O ₂ concentration; use Methods 6 or 6C (40 CFR part 60, appendix A-4) for certifying the SO ₂ monitor and Methods 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O ₂ monitor; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
6. Reduced sulfur and O ₂ continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an O ₂ monitor for correcting the data for excess air unless exempted	Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; span value is 450 ppm reduced sulfur, or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O ₂ concentration; use Methods 15 or 15A (40 CFR part 60, appendix A-5) for certifying the reduced sulfur monitor and Methods 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O ₂ monitor; if Method 3A or 3B yields O ₂ concentrations below 0.25 percent during the performance evaluation, the O ₂ concentration can be assumed to be zero and the O ₂ monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
7. Instrument with an air or O ₂ dilution and oxidation system to convert reduced sulfur to SO ₂ for continuously monitoring the concentration of SO ₂ instead of reduced sulfur monitor and O ₂ monitor	Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm SO ₂ or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O ₂ concentration; use Methods 15 or 15A (40 CFR part 60, appendix A-5) for certifying the reduced sulfur monitor and 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O ₂ monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
8. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an O ₂ monitor for correcting the data for excess air	Performance specification 5 (40 CFR part 60, appendix B).
9. O ₂ monitor for oxygen concentration	If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60,

	appendix B; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
--	---

[80 FR 75317, Dec. 1, 2015]

[↑ Back to Top](#)

Table 41 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Parameter Monitoring Systems

As stated in §63.1572(c)(1), you shall meet each requirement in the following table that applies to you.

If you use . . .	You shall . . .
1. pH strips	Use pH strips with an accuracy of ± 10 percent.
2. pH meter	Locate the pH sensor in a position that provides a representative measurement of pH; ensure the sample is properly mixed and representative of the fluid to be measured.
	Use a pH sensor with an accuracy of at least ± 0.2 pH units.
	Check the pH meter's calibration on at least one point at least once daily; check the pH meter's calibration on at least two points at least once quarterly; at least monthly, inspect all components for integrity and all electrical components for continuity; record the results of each calibration check and inspection.
3. Colormetric tube sampling system	Use a colormetric tube sampling system with a printed numerical scale in ppmv, a standard measurement range of 1 to 10 ppmv (or 1 to 30 ppmv if applicable), and a standard deviation for measured values of no more than ± 15 percent. System must include a gas detection pump and hot air probe if needed for the measurement range.
4. CO ₂ , O ₂ , and CO monitors for coke burn-off rate	a. Locate the concentration sensor so that it provides a representative measurement of the content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured.
	Use a sensor with an accuracy of at least ± 1 percent of the range of the sensor or to a nominal gas concentration of ± 0.5 percent, whichever is greater.
	Use a monitor that is able to measure concentration on a dry basis or is able to correct for moisture content and record on a dry basis.
	Conduct calibration checks at least annually; conduct calibration

	checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection.
	b. As an alternative, the requirements in 40 CFR 60.105a(b)(2) may be used.
5. BLD	Follow the requirements in 40 CFR 60.105a(c).
6. Voltage, secondary current, or total power input sensors	Use meters with an accuracy of at least ± 5 percent over the operating range.
	Each time that the unit is not operating, confirm that the meters read zero. Conduct a calibration check at least annually; conduct calibration checks following any period of more than 24 hours throughout which the meter reading exceeds the manufacturer's specified maximum operating range; at least monthly, inspect all components of the continuous parameter monitoring system for integrity and all electrical connections for continuity; record the results of each calibration check and inspection.
7. Pressure/Pressure drop ¹ sensors	Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
	Use a gauge with an accuracy of at least ± 5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.
	Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated; using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor; at least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor; record the results of each calibration check and inspection.
8. Air flow rate, gas flow rate, or total water (or scrubbing liquid) flow rate sensors	Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances. If you elect to comply with Option 3 (Ni lb/hr) or Option 4 (Ni lb/1,000 lb of coke burn-off) for the HAP metal emission limitations in §63.1564, install the

	continuous parameter monitoring system for gas flow rate as close as practical to the continuous opacity monitoring system; and if you don't use a continuous opacity monitoring system, install the continuous parameter monitoring system for gas flow rate as close as practical to the control device.
	Use a flow rate sensor with an accuracy of at least ± 5 percent over the normal range of flow measured, or 1.9 liter per minute (0.5 gallons per minute), whichever is greater, for liquid flow.
	Use a flow rate sensor with an accuracy of at least ± 5 percent over the normal range of flow measured, or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow.
	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor; at least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor; record the results of each calibration check and inspection.
9. Temperature sensors	Locate the temperature sensor in the combustion zone, or in the ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs or in the ductwork immediately downstream of the regenerator; locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
	Use a temperature sensor with an accuracy of at least ± 1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor; record the results of each calibration check and inspection.
10. Oxygen content sensors ²	Locate the oxygen sensor so that it provides a representative measurement of the oxygen content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured.
	Use an oxygen sensor with an accuracy of at least ± 1 percent of the range of the sensor or to a nominal gas concentration of ± 0.5 percent, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration

	checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new oxygen sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection.
--	---

¹Not applicable to non-venturi wet scrubbers of the jet-ejector design.

²This does not replace the requirements for oxygen monitors that are required to use continuous emissions monitoring systems. The requirements in this table apply to oxygen sensors that are continuous parameter monitors, such as those that monitor combustion zone oxygen concentration and regenerator exit oxygen concentration.

[80 FR 75318, Dec. 1, 2015]

[↑ Back to Top](#)

Table 42 to Subpart UUU of Part 63—Additional Information for Initial Notification of Compliance Status

As stated in §63.1574(d), you shall meet each requirement in the following table that applies to you.

For . . .	You shall provide this additional information . . .
1. Identification of affected sources and emission points.	Nature, size, design, method of operation, operating design capacity of each affected source; identify each emission point for each HAP; identify any affected source or vent associated with an affected source not subject to the requirements of subpart UUU.
2. Initial compliance	Identification of each emission limitation you will meet for each affected source, including any option you select (i.e., NSPS, PM or Ni, flare, percent reduction, concentration, options for bypass lines); if applicable, certification that you have already conducted a performance test to demonstrate initial compliance with the NSPS for an affected source; certification that the vents meet the applicable emission limit and the continuous opacity or that the emission monitoring system meets the applicable performance specification; if applicable, certification that you have installed and verified the operational status of equipment by your compliance date for each bypass line that meets the requirements of Option 2, 3, or 4 in §63.1569 and what equipment you installed; identification of the operating limit for each affected source, including supporting documentation; if your affected source is subject to the NSPS, certification of compliance with NSPS emission limitations and performance specifications; a brief description of performance test

	conditions (capacity, feed quality, catalyst, etc.); an engineering assessment (if applicable); and if applicable, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the Method 22 test.
3. Continuous compliance	Each monitoring option you elect; and identification of any unit or vent for which monitoring is not required; and the definition of “operating day.” (This definition, subject to approval by the applicable permitting authority, must specify the times at which a 24-hr operating day begins and ends.)

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

[↑ Back to Top](#)

Table 43 to Subpart UUU of Part 63—Requirements for Reports

As stated in §63.1575(a), you shall meet each requirement in the following table that applies to you.

You must submit . . .	The report must contain . . .	You shall submit the report . . .
1. A compliance report	If there are no deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in §63.1575(c) through (e)	Semiannually according to the requirements in §63.1575(b).
2. Performance test and CEMS performance evaluation data	On and after January 30, 2019, the information specified in §63.1575(k)(1)	Within 60 days after the date of completing each test according to the requirements in §63.1575(k).

[80 FR 75319, Dec. 1, 2015]

[↑ Back to Top](#)

Table 44 to Subpart UUU of Part 63—Applicability of NESHAP General Provisions to Subpart UUU

As stated in §63.1577, you shall meet each requirement in the following table that applies to you.

Citation	Subject	Applies to subpart UUU	Explanation
§63.1(a)(1)-(4)	General Applicability	Yes	
§63.1(a)(5)	[Reserved]	Not applicable	
§63.1(a)(6)		Yes	Except the correct mail drop (MD) number is C404-04.
§63.1(a)(7)-(9)	[Reserved]	Not applicable	
§63.1(a)(10)-(12)		Yes	Except that this subpart specifies calendar or operating day.
§63.1(b)(1)	Initial Applicability Determination for this part	Yes	
§63.1(b)(2)	[Reserved]	Not applicable	
§63.1(b)(3)		Yes	
§63.1(c)(1)	Applicability of this part after a Relevant Standard has been set under this part	Yes	
§63.1(c)(2)		No	Area sources are not subject to this subpart.
§63.1(c)(3)-(4)	[Reserved]	Not applicable	
§63.1(c)(5)		Yes	
§63.1(d)	[Reserved]	Not applicable	
§63.1(e)	Applicability of Permit Program	Yes	
§63.2	Definitions	Yes	§63.1579 specifies that if the same term is defined in subparts A and UUU of this part, it shall have the meaning given in this subpart.
§63.3	Units and Abbreviations	Yes	
§63.4(a)(1)-(2)	Prohibited Activities	Yes	

§63.4(a)(3)-(5)	[Reserved]	Not applicable	
§63.4(b)-(c)	Circumvention and Fragmentation	Yes	
§63.5(a)	Construction and Reconstruction	Yes	
§63.5(b)(1)		Yes	
§63.5(b)(2)	[Reserved]	Not applicable	
§63.5(b)(3)-(4)		Yes	In §63.5(b)(4), replace the reference to §63.9(b) with §63.9(b)(4) and (5).
§63.5(b)(5)	[Reserved]	Not applicable	
§63.5(b)(6)		Yes	
§63.5(c)	[Reserved]	Not applicable	
§63.5(d)(1)(i)	Application for Approval of Construction or Reconstruction—General Application Requirements	Yes	Except this subpart specifies the application is submitted as soon as practicable before startup but not later than 90 days after the promulgation date if construction or reconstruction had commenced and initial startup had not occurred before promulgation.
§63.5(d)(1)(ii)		Yes	Except that emission estimates specified in §63.5(d)(1)(ii)(H) are not required, and §63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
§63.5(d)(1)(iii)		No	This subpart specifies submission of notification of compliance status.
§63.5(d)(2)		Yes	
§63.5(d)(3)		Yes	
§63.5(d)(4)		Yes	
§63.5(e)	Approval of Construction or Reconstruction	Yes	
§63.5(f)(1)	Approval of Construction or Reconstruction Based on State Review	Yes	
§63.5(f)(2)		Yes	Except that the cross-reference to

			§63.9(b)(2) does not apply.
§63.6(a)	Compliance with Standards and Maintenance—Applicability	Yes	
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Yes	
§63.6(b)(5)		Yes	Except that this subpart specifies different compliance dates for sources.
§63.6(b)(6)	[Reserved]	Not applicable	
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Yes	
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Yes	Except that this subpart specifies different compliance dates for sources subject to Tier II gasoline sulfur control requirements.
§63.6(c)(3)-(4)	[Reserved]	Not applicable	
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Yes	
§63.6(d)	[Reserved]	Not applicable	
§63.6(e)(1)(i)	General Duty to Minimize Emissions	No	See §63.1570(c) for general duty requirement.
§63.6(e)(1)(ii)	Requirement to Correct Malfunctions as Soon as Possible	No	
§63.6(e)(1)(iii)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(e)(2)	[Reserved]	Not Applicable	
§63.6(e)(3)(i)	Startup, Shutdown, and Malfunction Plan Requirements	No	
§63.6(e)(3)(ii)	[Reserved]	Not applicable	
§63.6(e)(3)(iii)-(ix)		No	

§63.6(f)(1)	SSM Exemption	No	
§63.6(f)(2)(i)-(iii)(C)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(f)(2)(iii)(D)		Yes	
§63.6(f)(2)(iv)-(v)		Yes	
§63.6(f)(3)		Yes	Except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.1570(c).
§63.6(g)	Alternative Standard	Yes	
§63.6(h)(1)	SSM Exemption for Opacity/VE Standards	No	
§63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	No	This subpart specifies methods.
§63.6(h)(2)(ii)	[Reserved]	Not applicable	
§63.6(h)(2)(iii)		Yes	
§63.6(h)(3)	[Reserved]	Not applicable	
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Yes	Applies to Method 22 (40 CFR part 60, appendix A-7) tests.
§63.6(h)(5)	Conducting Opacity/VE Observations	No	
§63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Yes	Applies to Method 22 (40 CFR part 60, appendix A-7) observations.
§63.6(h)(7)(i)	Report COM Monitoring Data from Performance Test	Yes	
§63.6(h)(7)(ii)	Using COM Instead of Method 9	No	
§63.6(h)(7)(iii)	Averaging Time for COM during Performance Test	Yes	
§63.6(h)(7)(iv)	COM Requirements	Yes	
§63.6(h)(7)(v)	COMS Results and Visual Observations	Yes	
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Yes	
§63.6(h)(9)	Adjusted Opacity Standard	Yes	
§63.6(i)(1)-(14)	Extension of Compliance	Yes	Extension of compliance under §63.6(i)(4) not applicable to a

			facility that installs catalytic cracking feed hydrotreating and receives an extended compliance date under §63.1563(c).
§63.6(i)(15)	[Reserved]	Not applicable	
§63.6(i)(16)		Yes	
§63.6(j)	Presidential Compliance Exemption	Yes	
§63.7(a)(1)	Performance Test Requirements Applicability	Yes	Except that this subpart specifies the applicable test and demonstration procedures.
§63.7(a)(2)	Performance Test Dates	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after the compliance date.
§63.7(a)(3)	Section 114 Authority	Yes	
§63.7(a)(4)	Force Majeure	Yes	
§63.7(b)	Notifications	Yes	Except that this subpart specifies notification at least 30 days prior to the scheduled test date rather than 60 days.
§63.7(c)	Quality Assurance Program/Site-Specific Test Plan	Yes	Except that when this subpart specifies to use 40 CFR part 60, appendix F, out of control periods are to be defined as specified in part 60, appendix F.
§63.7(d)	Performance Test Facilities	Yes	
§63.7(e)(1)	Performance Testing	No	See §63.1571(b)(1).
§63.7(e)(2)-(4)	Conduct of Tests	Yes	
§63.7(f)	Alternative Test Method	Yes	
§63.7(g)	Data Analysis, Recordkeeping, Reporting	Yes	Except performance test reports must be submitted with notification of compliance status due 150 days after the compliance date, and §63.7(g)(2) is reserved and does not apply.
§63.7(h)	Waiver of Tests	Yes	
§63.8(a)(1)	Monitoring Requirements-Applicability	Yes	
§63.8(a)(2)	Performance Specifications	Yes	

§63.8(a)(3)	[Reserved]	Not applicable	
§63.8(a)(4)	Monitoring with Flares	Yes	Except that for a flare complying with §63.670, the cross-reference to §63.11 in this paragraph does not include §63.11(b).
§63.8(b)(1)	Conduct of Monitoring	Yes	
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Yes	This subpart specifies the required monitoring locations.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Yes	
§63.8(c)(1)(i)	General Duty to Minimize Emissions and CMS Operation	No	See §63.1570(c).
§63.8(c)(1)(ii)	Keep Necessary Parts for CMS	Yes	
§63.8(c)(1)(iii)	Requirement to Develop SSM Plan for CMS	No	
§63.8(c)(2)-(3)	Monitoring System Installation	Yes	Except that this subpart specifies that for continuous parameter monitoring systems, operational status verification includes completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately.
§63.8(c)(4)	Continuous Monitoring System Requirements	Yes	
§63.8(c)(5)	COMS Minimum Procedures	Yes	
§63.8(c)(6)	CMS Requirements	Yes	
§63.8(c)(7)-(8)	CMS Requirements	Yes	
§63.8(d)(1)-(2)	Quality Control Program for CMS	Yes	
§63.8(d)(3)	Written Procedures for CMS	No	
§63.8(e)	CMS Performance Evaluation	Yes	Except that results are to be submitted as part of the Notification Compliance Status due 150 days after the compliance

			date.
§63.8(f)(1)-(5)	Alternative Monitoring Methods	Yes	Except that this subpart specifies procedures for requesting alternative monitoring systems and alternative parameters.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Yes	Applicable to continuous emission monitoring systems if performance specification requires a relative accuracy test audit.
§63.8(g)(1)-(4)	Reduction of Monitoring Data	Yes	Applies to continuous opacity monitoring system or continuous emission monitoring system.
§63.8(g)(5)	Data Reduction	No	This subpart specifies requirements.
§63.9(a)	Notification Requirements—Applicability	Yes	Duplicate Notification of Compliance Status report to the Regional Administrator may be required.
§63.9(b)(1)-(2)	Initial Notifications	Yes	Except that notification of construction or reconstruction is to be submitted as soon as practicable before startup but no later than 30 days after the effective date if construction or reconstruction had commenced but startup had not occurred before the effective date.
§63.9(b)(3)	[Reserved]	Not applicable	
§63.9(b)(4)-(5)	Initial Notification Information	Yes	Except §63.9(b)(4)(ii)-(iv), which are reserved and do not apply.
§63.9(c)	Request for Extension of Compliance	Yes	
§63.9(d)	New Source Notification for Special Compliance Requirements	Yes	
§63.9(e)	Notification of Performance Test	Yes	Except that notification is required at least 30 days before test.
§63.9(f)	Notification of VE/Opacity Test	Yes	
§63.9(g)	Additional Notification Requirements for Sources with Continuous Monitoring	Yes	

	Systems		
§63.9(h)	Notification of Compliance Status	Yes	Except that this subpart specifies the notification is due no later than 150 days after compliance date, and except that the reference to §63.5(d)(1)(ii)(H) in §63.9(h)(5) does not apply.
§63.9(i)	Adjustment of Deadlines	Yes	
§63.9(j)	Change in Previous Information	Yes	
63.10(a)	Recordkeeping and Reporting Applicability	Yes	
§63.10(b)(1)	General Recordkeeping Requirements	Yes	
§63.10(b)(2)(i)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns	No	
§63.10(b)(2)(ii)	Recordkeeping of Malfunctions	No	See §63.1576(a)(2) for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the volume of each regulated pollutant emitted over the standard; and (3) actions taken to minimize emissions and correct the failure.
§63.10(b)(2)(iii)	Maintenance Records	Yes	
§63.10(b)(2)(iv)-(v)	Actions Taken to Minimize Emissions During SSM	No	
§63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes	
§63.10(b)(2)(vii)-(xiv)	Other CMS Requirements	Yes	
§63.10(b)(3)	Recordkeeping for Applicability Determinations.	Yes	
§63.10(c)(1)-(6)	Additional Records for Continuous Monitoring Systems	Yes	Except §63.10(c)(2)-(4), which are Reserved and do not apply.
§63.10(c)(7)-(8)	Additional Recordkeeping Requirements for CMS—Identifying Exceedances and Excess Emissions	Yes	

§63.10(c)(9)	[Reserved]	Not applicable	
§63.10(c)(10)	Recording Nature and Cause of Malfunctions	No	See §63.1576(a)(2) for malfunctions recordkeeping requirements.
§63.10(c)(11)	Recording Corrective Actions	No	See §63.1576(a)(2) for malfunctions recordkeeping requirements.
§63.10(c)(12)-(14)	Additional CMS Recordkeeping Requirements	Yes	
§63.10(c)(15)	Use of SSM Plan	No	
§63.10(d)(1)	General Reporting Requirements	Yes	
§63.10(d)(2)	Performance Test Results	No	This subpart requires performance test results to be reported as part of the Notification of Compliance Status due 150 days after the compliance date.
§63.10(d)(3)	Opacity or VE Observations	Yes	
§63.10(d)(4)	Progress Reports	Yes	
§63.10(d)(5)	SSM Reports	No	See §63.1575(d) for CPMS malfunction reporting and §63.1575(e) for COMS and CEMS malfunction reporting.
§63.10(e)(1)-(2)	Additional CMS Reports	Yes	Except that reports of performance evaluations must be submitted in Notification of Compliance Status.
§63.10(e)(3)	Excess Emissions/CMS Performance Reports	No	This subpart specifies the applicable requirements.
§63.10(e)(4)	COMS Data Reports	Yes	
§63.10(f)	Recordkeeping/Reporting Waiver	Yes	
§63.11(a)	Control Device and Work Practice Requirements Applicability	Yes	
§63.11(b)	Flares	Yes	Except that flares complying with §63.670 are not subject to the requirements of §63.11(b).
§63.11(c)-(e)	Alternative Work Practice for Monitoring Equipment for Leaks	Yes	
§63.12	State Authority and	Yes	

	Delegations		
§63.13	Addresses	Yes	
§63.14	Incorporation by Reference	Yes	
§63.15	Availability of Information and Confidentiality	Yes	
§63.16	Performance Track Provisions	Yes	

[80 FR 75320, Dec. 1, 2015]

[↑ Back to Top](#)

Appendix A to Subpart UUU of Part 63—Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)

1.0 Scope and Application.

1.1 Analytes. The analytes for which this method is applicable include any elements with an atomic number between 11 (sodium) and 92 (uranium), inclusive. Specific analytes for which this method was developed include:

Analyte	CAS No.	Minimum detectable limit
Nickel compounds	7440-02-0	<2 % of span.
Total chlorides	16887-00-6	<2 % of span.

1.2 Applicability. This method is applicable to the determination of analyte concentrations on catalyst particles. This method is applicable for catalyst particles obtained from the fluid catalytic cracking unit (FCCU) regenerator (*i.e.*, equilibrium catalyst), from air pollution control systems operated for the FCCU catalyst regenerator vent (FCCU fines), from catalytic reforming units (CRU), and other processes as specified within an applicable regulation. This method is applicable only when specified within the regulation.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from the analytical method.

2.0 Summary of Method.

2.1 A representative sample of catalyst particles is collected, prepared, and analyzed for analyte concentration using either energy or wavelength dispersive X-ray fluorescent (XRF) spectrometry instrumental analyzers. In both types of XRF spectrometers, the instrument

irradiates the sample with high energy (primary) x-rays and the elements in the sample absorb the x-rays and then re-emit secondary (fluorescent) x-rays of characteristic wavelengths for each element present. In energy dispersive XRF spectrometers, all secondary x-rays (of all wavelengths) enter the detector at once. The detector registers an electric current having a height proportional to the photon energy, and these pulses are then separated electronically, using a pulse analyzer. In wavelength dispersive XRF spectrometers, the secondary x-rays are dispersed spatially by crystal diffraction on the basis of wavelength. The crystal and detector are made to synchronously rotate and the detector then receives only one wavelength at a time. The intensity of the x-rays emitted by each element is proportional to its concentration, after correcting for matrix effects. For nickel compounds and total chlorides, the XRF instrument response is expected to be linear to analyte concentration. Performance specifications and test procedures are provided to ensure reliable data.

3.0 Definitions.

3.1 Measurement System. The total equipment required for the determination of analyte concentration. The measurement system consists of the following major subsystems:

3.1.1 Sample Preparation. That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or sample preparation prior to introducing the sample into the analyzer.

3.1.2 Analyzer. That portion of the system that senses the analyte to be measured and generates an output proportional to its concentration.

3.1.3 Data Recorder. A digital recorder or personal computer used for recording measurement data from the analyzer output.

3.2 Span. The upper limit of the gas concentration measurement range displayed on the data recorder.

3.3 Calibration Standards. Prepared catalyst samples or other samples of known analyte concentrations used to calibrate the analyzer and to assess calibration drift.

3.4 Energy Calibration Standard. Calibration standard, generally provided by the XRF instrument manufacturer, used for assuring accuracy of the energy scale.

3.5 Accuracy Assessment Standard. Prepared catalyst sample or other sample of known analyte concentrations used to assess analyzer accuracy error.

3.6 Zero Drift. The difference in the measurement system output reading from the initial value for zero concentration level calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.7 Calibration Drift. The difference in the measurement system output reading from the initial value for the mid-range calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.8 Spectral Interferences. Analytical interferences and excessive biases caused by elemental peak overlap, escape peak, and sum peak interferences between elements in the samples.

3.9 Calibration Curve. A graph or other systematic method of establishing the relationship between the analyzer response and the actual analyte concentration introduced to the analyzer.

3.10 Analyzer Accuracy Error. The difference in the measurement system output reading and the ideal value for the accuracy assessment standard.

4.0 Interferences.

4.1 Spectral interferences with analyte line intensity determination are accounted for within the method program. No action is required by the XRF operator once these interferences have been addressed within the method.

4.2 The X-ray production efficiency is affected by particle size for the very lightest elements. However, particulate matter (PM) 2.5 particle size effects are substantially < 1 percent for most elements. The calibration standards should be prepared with material of similar particle size or be processed (ground) to produce material of similar particle size as the catalyst samples to be analyzed. No additional correction for particle size is performed. Alternatively, the sample can be fused in order to eliminate any potential particle size effects.

5.0 Safety.

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 X-ray Exposure. The XRF uses X-rays; XRF operators should follow instrument manufacturer's guidelines to protect from accidental exposure to X-rays when the instrument is in operation.

5.3 Beryllium Window. In most XRF units, a beryllium (Be) window is present to separate the sample chamber from the X-ray tube and detector. The window is very fragile and brittle. Do not allow sample or debris to fall onto the window, and avoid using compressed air to clean the window because it will cause the window to rupture. If the window should rupture, note that Be metal is poisonous. Use extreme caution when collecting pieces of Be and consult the instrument manufacturer for advice on cleanup of the broken window and replacement.

6.0 Equipment and Supplies.

6.1 Measurement System. Use any measurement system that meets the specifications of this method listed in section 13. The typical components of the measurement system are described below.

6.1.1 Sample Mixer/Mill. Stainless steel, or equivalent to grind/mix catalyst and binders, if used, to produce uniform particle samples.

6.1.2 Sample Press/Fluxer. Stainless steel, or equivalent to produce pellets of sufficient size to fill analyzer sample window, or alternatively, a fusion device capable of preparing a fused disk of sufficient size to fill analyzer sample window.

6.1.3 Analytical Balance. ± 0.0001 gram accuracy for weighing prepared samples (pellets).

6.1.4 Analyzer. An XRF spectrometer to determine the analyte concentration in the prepared sample. The analyzer must meet the applicable performance specifications in section 13.

6.1.5 Data Recorder. A digital recorder or personal computer for recording measurement data. The data recorder resolution (*i.e.*, readability) must be 0.5 percent of span. Alternatively, a digital or analog meter having a resolution of 0.5 percent of span may be used to obtain the analyzer responses and the readings may be recorded manually.

7.0 Reagents and Standards.

7.1 Calibration Standards. The calibration standards for the analyzer must be prepared catalyst samples or other material of similar particle size and matrix as the catalyst samples to be tested that have known concentrations of the analytes of interest. Preparation (grinding/milling/fusion) of the calibration standards should follow the same processes used to prepare the catalyst samples to be tested. The calibration standards values must be established as the average of a minimum of three analyses using an approved EPA or ASTM method with instrument analyzer calibrations traceable to the U.S. National Institute of Standards and Technology (NIST), if available. The maximum percent deviation of the triplicate calibration standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). If the calibration analyses do not meet this criteria, the calibration standards must be re-analyzed. If unacceptable variability persists, new calibration standards must be prepared. Approved methods for the calibration standard analyses include, but are not limited to, EPA Methods 6010B, 6020, 7520, or 7521 of SW-846.1 Use a minimum of four calibration standards as specified below (see Figure 1):

7.1.1 High-Range Calibration Standard. Concentration equivalent to 80 to 100 percent of the span. The concentration of the high-range calibration standard should exceed the maximum concentration anticipated in the catalyst samples.

7.1.2 Mid-Range Calibration Standard. Concentration equivalent to 40 to 60 percent of the span.

7.1.3 Low-Range Calibration Standard. Concentration equivalent to 1 to 20 percent of the span. The concentration of the low-range calibration standard should be selected so that it is less than either one-fourth of the applicable concentration limit or of the lowest concentration anticipated in the catalyst samples.

7.1.4 Zero Calibration Standard. Concentration of less than 0.25 percent of the span.

7.2 Accuracy Assessment Standard. Prepare an accuracy assessment standard and determine the ideal value for the accuracy assessment standard following the same procedures used to prepare and analyze the calibration standards as described in section 7.1. The maximum percent deviation of the triplicate accuracy assessment standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). The concentration equivalent of the accuracy assessment standard must be between 20 and 80 percent of the span.

7.3 Energy Calibration Standard. Generally, the energy calibration standard will be provided by the XRF instrument manufacturer for energy dispersive spectrometers. Energy calibration is performed using the manufacturer's recommended calibration standard and involves measurement of a specific energy line (based on the metal in the energy calibration standard). This is generally an automated procedure used to assure the accuracy of the energy scale. This calibration standard may not be applicable to all models of XRF spectrometers (particularly wavelength dispersive XRF spectrometers).

8.0 Sample Collection, Preservation, Transport, and Storage. [Reserved]

9.0 Quality Control.

9.1 Energy Calibration. For energy dispersive spectrometers, conduct the energy calibration by analyzing the energy calibration standard provided by the manufacturer. The energy calibration involves measurement of a specific energy line (based on the metal in the energy calibration standard) and then determination of the difference between the measured peak energy value and the ideal value. This analysis, if applicable, should be performed daily prior to any sample analyses to check the instrument's energy scale. This is generally an automated procedure and assures the accuracy of the energy scale. If the energy scale calibration process is not automated, follow the manufacturer's procedures to manually adjust the instrument, as necessary.

9.2 Zero Drift Test. Conduct the zero drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the zero calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.3 Calibration Drift Test. Conduct the calibration drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the mid-range calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.4 Analyzer Accuracy Test. Conduct the analyzer accuracy test by analyzing the accuracy assessment standard and comparing the value output by the measurement system with the ideal value for the accuracy assessment standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

10.0 Calibration and Standardization.

10.1 Perform the initial calibration and set-up following the instrument manufacturer's instructions. These procedures should include, at a minimum, the major steps listed in sections 10.2 and 10.3. Subsequent calibrations are to be performed when either a quality assurance/quality control (QA/QC) limit listed in section 13 is exceeded or when there is a change in the excitation conditions, such as a change in the tube, detector, X-ray filters, or signal processor. Calibrations are typically valid for 6 months to 1 year.

10.2 Instrument Calibration. Calibration is performed initially with calibration standards of similar matrix and binders, if used, as the samples to be analyzed (see Figure 1).

10.3 Reference Peak Spectra. Acquisition of reference spectra is required only during the initial calibration. As long as no processing methods have changed, these peak shape references remain valid. This procedure consists of placing the standards in the instrument and acquiring individual elemental spectra that are stored in the method file with each of the analytical conditions. These reference spectra are used in the standard deconvolution of the unknown spectra.

11.0 Analytical Procedure.

11.1 Sample Preparation. Prepare catalyst samples using the same procedure used to prepare the calibration standards. Measure and record the weight of sample used. Measure and record the amount of binder, if any, used. Pellets or films must be of sufficient size to cover the analyzer sample window.

11.2 Sample Analyses. Place the prepared catalyst samples into the analyzer. Follow the manufacturer's instructions for analyzing the samples.

11.3 Record and Store Data. Use a digital recorder or personal computer to record and store results for each sample. Record any mechanical or software problems encountered during the analysis.

12.0 Data Analysis and Calculations.

Carry out the following calculations, retaining at least one extra significant figure beyond that of the acquired data. Round off figures after final calculation.

12.1 Drift. Calculate the zero and calibration drift for the tests described in sections 9.2 and 9.3 (see also Figure 2) as follows:

$$\text{QC Value} = \frac{\text{CurrentAnalyzerCal.Response} - \text{InitialCal.Response}}{\text{Span}} \times 100 \quad (\text{Eq. A-1})$$

[View or download PDF](#)

Where:

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

InitialCal.Response = Initial instrument response for calibration standard;

QC Value = QC metric (zero drift or calibration drift), percent of span;

Span = Span of the monitoring system.

12.2 Analyzer Accuracy. Calculate the analyzer accuracy error for the tests described in section 9.4 (see also Figure 2) as follows:

$$\text{Accuracy Value} = \frac{\text{CurrentAnalyzerCal.Response} - \text{IdealCal.Response}}{\text{IdealCal.Response}} \times 100 \quad (\text{Eq. A-2})$$

[View or download PDF](#)

Where:

Accuracy Value = Percent difference of instrument response to the ideal response for the accuracy assessment standard;

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

IdealCal.Response = Ideal instrument response for the accuracy assessment standard.

13.0 Method Performance.

13.1 Analytical Range. The analytical range is determined by the instrument design. For this method, a portion of the analytical range is selected by choosing the span of the monitoring system. The span of the monitoring system must be selected such that it encompasses the range of concentrations anticipated to occur in the catalyst sample. If applicable, the span must be selected such that the analyte concentration equivalent to the emission standard is not less than 30 percent of the span. If the measured analyte concentration exceeds the concentration of the high-range calibration standard, the sample analysis is considered invalid. Additionally, if the measured analyte concentration is less than the concentration of the low-range calibration standard but above the detectable limit, the sample analysis results must be flagged with a footnote stating, in effect, that the analyte was detected but that the reported concentration is below the lower quantitation limit.

13.2 Minimum Detectable Limit. The minimum detectable limit depends on the signal-to-noise ratio of the measurement system. For a well-designed system, the minimum detectable limit should be less than 2 percent of the span.

13.3 Zero Drift. Less than ± 2 percent of the span.

13.4 Calibration Drift. Less than ± 5 percent of the span.

13.5 Analyzer Accuracy Error. Less than ± 10 percent.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 References.

1. U.S. Environmental Protection Agency. 1998. Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. EPA Publication No. SW-846, Revision 5 (April 1998). Office of Solid Waste, Washington, DC.

18.0 Tables, Diagrams, Flowcharts, and Validation Data.

Date:					
Analytic Method Used:					
	Zero ^a	Low-Range ^b	Mid-Range ^c	High-Range ^d	Accuracy Std ^e
Sample Run:					
1					
2					
3					
Average					
Maximum Percent Deviation					

^a Average must be less than 0.25 percent of span.

^b Average must be 1 to 20 percent of span.

^c Average must be 40 to 60 percent of span.

^d Average must be 80 to 100 percent of span.

^e Average must be 20 to 80 percent of span.

Figure 1. Data Recording Sheet for Analysis of Calibration Samples.

Source Identification:

Run Number:

Test Personnel:

Span:

Date:

	Initial calibration response	Current analyzer calibration response	Drift (percent of span)
Zero Standard			
Mid-range Standard			
	Ideal calibration response	Current analyzer calibration response	Accuracy error (percent of ideal)
Accuracy Standard			

Figure 2. Data Recording Sheet for System Calibration Drift Data.

[70 FR 6970, Feb. 9, 2005, as amended at 80 FR 75325, Dec. 1, 2015]

Appendix Q

Subpart EEEE—National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

Contents

[What This Subpart Covers](#)

[§63.2330 What is the purpose of this subpart?](#)

[§63.2334 Am I subject to this subpart?](#)

[§63.2338 What parts of my plant does this subpart cover?](#)

[§63.2342 When do I have to comply with this subpart?](#)

[§63.2343 What are my requirements for emission sources not requiring control?](#)

[Emission Limitations, Operating Limits, and Work Practice Standards](#)

[§63.2346 What emission limitations, operating limits, and work practice standards must I meet?](#)

[General Compliance Requirements](#)

[§63.2350 What are my general requirements for complying with this subpart?](#)

[Testing and Initial Compliance Requirements](#)

[§63.2354 What performance tests, design evaluations, and performance evaluations must I conduct?](#)

[§63.2358 By what date must I conduct performance tests and other initial compliance demonstrations?](#)

[§63.2362 When must I conduct subsequent performance tests?](#)

[§63.2366 What are my monitoring installation, operation, and maintenance requirements?](#)

[§63.2370 How do I demonstrate initial compliance with the emission limitations, operating limits, and work practice standards?](#)

[Continuous Compliance Requirements](#)

[§63.2374 When do I monitor and collect data to demonstrate continuous compliance and how do I use the collected data?](#)

[§63.2378 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?](#)

[Notifications, Reports, and Records](#)

[§63.2382 What notifications must I submit and when and what information should be submitted?](#)

[§63.2386 What reports must I submit and when and what information is to be submitted in each?](#)

[§63.2390 What records must I keep?](#)

[§63.2394 In what form and how long must I keep my records?](#)

[Other Requirements and Information](#)

[§63.2396 What compliance options do I have if part of my plant is subject to both this subpart and another subpart?](#)

[§63.2398 What parts of the General Provisions apply to me?](#)

[§63.2402 Who implements and enforces this subpart?](#)

[§63.2406 What definitions apply to this subpart?](#)

[Table 1 to Subpart EEEE of Part 63—Organic Hazardous Air Pollutants](#)

[Table 2 to Subpart EEEE of Part 63—Emission Limits](#)

[Table 3 to Subpart EEEE of Part 63—Operating Limits—High Throughput Transfer Racks](#)

[Table 4 to Subpart EEEE of Part 63—Work Practice Standards](#)

[Table 5 to Subpart EEEE of Part 63—Requirements for Performance Tests and Design Evaluations](#)

[Table 6 to Subpart EEEE of Part 63—Initial Compliance With Emission Limits](#)

[Table 7 to Subpart EEEE of Part 63—Initial Compliance With Work Practice Standards](#)

[Table 8 to Subpart EEEE of Part 63—Continuous Compliance With Emission Limits](#)

[Table 9 to Subpart EEEE of Part 63—Continuous Compliance With Operating Limits—High Throughput Transfer Racks](#)

[Table 10 to Subpart EEEE of Part 63—Continuous Compliance With Work Practice Standards](#)

[Table 11 to Subpart EEEE of Part 63—Requirements for Reports](#)

[Table 12 to Subpart EEEE of Part 63—Applicability of General Provisions to Subpart EEEE](#)

SOURCE: 69 FR 5063, Feb. 3, 2004, unless otherwise noted.

[↑ Back to Top](#)

What This Subpart Covers

[↑ Back to Top](#)

§63.2330 What is the purpose of this subpart?

This subpart establishes national emission limitations, operating limits, and work practice standards for organic hazardous air pollutants (HAP) emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards.

[↑ Back to Top](#)

§63.2334 Am I subject to this subpart?

(a) Except as provided for in paragraphs (b) and (c) of this section, you are subject to this subpart if you own or operate an OLD operation that is located at, or is part of, a major source of HAP emissions. An OLD operation may occupy an entire plant site or be collocated with other industrial (*e.g.*, manufacturing) operations at the same plant site.

(b) Organic liquid distribution operations located at research and development facilities, consistent with section 112(c)(7) of the Clean Air Act (CAA), are not subject to this subpart.

(c) Organic liquid distribution operations do not include the activities and equipment, including product loading racks, used to process, store, or transfer organic liquids at facilities listed in paragraph (c) (1) and (2) of this section.

(1) Oil and natural gas production field facilities, as the term “facility” is defined in §63.761 of subpart HH.

(2) Natural gas transmission and storage facilities, as the term “facility” is defined in §63.1271 of subpart HHH.

[↑ Back to Top](#)

§63.2338 What parts of my plant does this subpart cover?

(a) This subpart applies to each new, reconstructed, or existing OLD operation affected source.

(b) Except as provided in paragraph (c) of this section, the affected source is the collection of activities and equipment used to distribute organic liquids into, out of, or within a facility that is a major source of HAP. The affected source is composed of:

(1) All storage tanks storing organic liquids.

(2) All transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers.

(3) All equipment leak components in organic liquids service that are associated with:

(i) Storage tanks storing organic liquids;

(ii) Transfer racks loading or unloading organic liquids;

(iii) Pipelines that transfer organic liquids directly between two storage tanks that are subject to this subpart;

(iv) Pipelines that transfer organic liquids directly between a storage tank subject to this subpart and a transfer rack subject to this subpart; and

(v) Pipelines that transfer organic liquids directly between two transfer racks that are subject to this subpart.

(4) All transport vehicles while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(5) All containers while they are loading or unloading organic liquids at transfer racks subject to this subpart.

(c) The equipment listed in paragraphs (c)(1) through (4) of this section and used in the identified operations is excluded from the affected source.

(1) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another 40 CFR part 63 national emission standards for hazardous air pollutants (NESHAP).

(2) Non-permanent storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used in special situation distribution loading and unloading operations (such as maintenance or upset liquids management).

(3) Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components when used to conduct maintenance activities, such as stormwater management, liquid removal from tanks for inspections and maintenance, or changeovers to a different liquid stored in a storage tank.

(d) An affected source is a new affected source if you commenced construction of the affected source after April 2, 2002, and you meet the applicability criteria in §63.2334 at the time you commenced operation.

(e) An affected source is reconstructed if you meet the criteria for reconstruction as defined in §63.2.

(f) An affected source is existing if it is not new or reconstructed.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42904, July 28, 2006]

[!\[\]\(9c2e8d1b5bd77cb5c9f83b7a9cff79fd_img.jpg\) Back to Top](#)

§63.2342 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the schedule identified in paragraph (a)(1), (a)(2), or (a)(3) of this section, as applicable.

(1)(i) Except as provided in paragraph (a)(1)(ii) of this section, if you startup your new affected source on or before February 3, 2004 or if you reconstruct your affected source on or before February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart no later than February 3, 2004.

(ii) For any emission source listed in paragraph §63.2338(b) at an affected source that commenced construction or reconstruction after April 2, 2002, but before February 3, 2004, that is required to be controlled based on the applicability criteria in this subpart, but:

(A) Would not have been required to be controlled based on the applicability criteria as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later; or

(B) Would have been subject to a less stringent degree of control requirement as proposed for this subpart, you must comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section or at startup, whichever is later, and if you start up your affected new or reconstructed source before February 5, 2007, you must comply with the emission limitations, operating limits, and work practice standards for each such emission source as proposed for this subpart, until you are required to comply with the emission limitations, operating limits, and work practice standards in this subpart for each such emission source based on the schedule found in paragraph (b) of this section.

(2) If you commence construction of or reconstruct your affected source after February 3, 2004, you must comply with the emission limitations, operating limits, and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(3) If, after startup of a new affected source, the total actual annual facility-level organic liquid loading volume at that source exceeds the criteria for control in Table 2 to this subpart, items 9 and 10, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(b)(1) If you have an existing affected source, you must comply with the emission limitations, operating limits, and work practice standards for existing affected sources no later than February 5, 2007, except as provided in paragraphs (b)(2) and (3) of this section.

(2) Floating roof storage tanks at existing affected sources must be in compliance with the work practice standards in Table 4 to this subpart, item 1, at all times after the next degassing and cleaning activity or within 10 years after February 3, 2004, whichever occurs first. If the first degassing and cleaning activity occurs during the 3 years following February 3, 2004, the compliance date is February 5, 2007.

(3)(i) If an addition or change other than reconstruction as defined in §63.2 is made to an existing affected facility that causes the total actual annual facility-level organic liquid loading volume to exceed the criteria for control in Table 2 to this subpart, items 7 and 8, the owner or operator must comply with the transfer rack requirements specified in §63.2346(b) immediately; that is, be in compliance the first day of the period following the end of the 3-year period triggering the control criteria.

(ii) If the owner or operator believes that compliance with the transfer rack emission limits cannot be achieved immediately, as specified in paragraph (b)(3)(i) of this section, the owner or operator may submit a request for a compliance extension, as specified in paragraphs (b)(3)(ii)(A) through (I) of this section. Subject to paragraph (b)(3)(ii)(B) of this section, until an extension of compliance has been granted by the Administrator (or a State with an approved permit program) under this paragraph (b)(3)(ii), the owner or operator of the transfer rack subject to the requirements of this section shall comply with all applicable requirements of this subpart. Advice on requesting an extension of compliance may be obtained from the Administrator (or the State with an approved permit program).

(A) *Submittal.* The owner or operator shall submit a request for a compliance extension to the Administrator (or a State, when the State has an approved 40 CFR part 70 permit program and the source is required to obtain a 40 CFR part 70 permit under that program, or a State, when the State has been delegated the authority to implement and enforce the emission standard for that source) seeking an extension allowing the source up to 1 additional year to comply with the transfer rack standard, if such additional period is necessary for the installation of controls. The owner or operator of the affected source who has requested an extension of compliance under this paragraph (b)(3)(ii)(A) and who is otherwise required to obtain a title V permit shall apply for such permit, or apply to have the source's title V permit revised to incorporate the conditions of the extension of compliance. The conditions of an extension of compliance granted under this paragraph (b)(3)(ii)(A) will be incorporated into the affected source's title V permit according to the provisions of 40 CFR part 70 or Federal title V regulations in this chapter (42 U.S.C. 7661), whichever are applicable.

(B) *When to submit.* (1) Any request submitted under paragraph (b)(3)(ii)(A) of this section must be submitted in writing to the appropriate authority no later than 120 days prior to the affected source's compliance date (as specified in paragraph (b)(3)(i) of this section), except as provided for in paragraph (b)(3)(ii)(B)(2) of this section. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(1) will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the date of denial.

(2) An owner or operator may submit a compliance extension request after the date specified in paragraph (b)(3)(ii)(B)(1) of this section provided the need for the compliance extension arose after that date, and before the otherwise applicable compliance date and the need arose due to circumstances beyond reasonable control of the owner or operator. This request must include, in addition to the information required in paragraph (b)(3)(ii)(C) of this section, a statement of the reasons additional time is needed and the date when the owner or operator first learned of the problems. Nonfrivolous requests submitted under this paragraph (b)(3)(ii)(B)(2) will stay the

applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the original compliance date.

(C) *Information required.* The request for a compliance extension under paragraph (b)(3)(ii)(A) of this section shall include the following information:

(1) The name and address of the owner or operator and the address of the existing source if it differs from the address of the owner or operator;

(2) The name, address, and telephone number of a contact person for further information;

(3) An identification of the organic liquid distribution operation and of the specific equipment for which additional compliance time is required;

(4) A description of the controls to be installed to comply with the standard;

(5) Justification for the length of time being requested; and

(6) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:

(i) The date by which on-site construction, installation of emission control equipment, or a process change is planned to be initiated;

(ii) The date by which on-site construction, installation of emission control equipment, or a process change is to be completed; and

(iii) The date by which final compliance is to be achieved.

(D) *Approval of request for extension of compliance.* Based on the information provided in any request made under paragraph (b)(3)(ii)(C) of this section, or other information, the Administrator (or the State with an approved permit program) may grant an extension of compliance with the transfer rack emission standard, as specified in paragraph (b)(3)(ii) of this section. The extension will be in writing and will—

(1) Identify each affected source covered by the extension;

(2) Specify the termination date of the extension;

(3) Specify the dates by which steps toward compliance are to be taken, if appropriate;

(4) Specify other applicable requirements to which the compliance extension applies (e.g., performance tests);

(5) Specify the contents of the progress reports to be submitted and the dates by which such reports are to be submitted, if required pursuant to paragraph (b)(3)(ii)(E) of this section.

(6) Under paragraph (b)(3)(ii) of this section, specify any additional conditions that the Administrator (or the State) deems necessary to assure installation of the necessary controls and protection of the health of persons during the extension period.

(E) *Progress reports.* The owner or operator of an existing source that has been granted an extension of compliance under paragraph (b)(3)(ii)(D) of this section may be required to submit to the Administrator (or the State with an approved permit program) progress reports indicating whether the steps toward compliance outlined in the compliance schedule have been reached.

(F) *Notification of approval or intention to deny.* (1) The Administrator (or the State with an approved permit program) will notify the owner or operator in writing of approval or intention to deny approval of a request for an extension of compliance within 30 calendar days after receipt of sufficient information to evaluate a request submitted under paragraph (b)(3)(ii) of this section. The Administrator (or the State) will notify the owner or operator in writing of the status of his/her application; that is, whether the application contains sufficient information to make a determination, within 30 calendar days after receipt of the original application and within 30 calendar days after receipt of any supplementary information that is submitted. The 30-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete. Failure by the Administrator to act within 30 calendar days to approve or disapprove a request submitted under paragraph (b)(3)(ii) of this section does not constitute automatic approval of the request.

(2) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(3) Before denying any request for an extension of compliance, the Administrator (or the State with an approved permit program) will notify the owner or operator in writing of the Administrator's (or the State's) intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator (or the State) before further action on the request.

(4) The Administrator's final determination to deny any request for an extension will be in writing and will set forth the specific grounds on which the denial is based. The final determination will be made within 30 calendar days after presentation of additional information or argument (if the application is complete), or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(G) *Termination of extension of compliance.* The Administrator (or the State with an approved permit program) may terminate an extension of compliance at an earlier date than specified if

any specification under paragraph (b)(3)(ii)(D)(3) or paragraph (b)(3)(ii)(D)(4) of this section is not met. Upon a determination to terminate, the Administrator will notify, in writing, the owner or operator of the Administrator's determination to terminate, together with:

(1) Notice of the reason for termination; and

(2) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the determination to terminate, additional information or arguments to the Administrator before further action on the termination.

(3) A final determination to terminate an extension of compliance will be in writing and will set forth the specific grounds on which the termination is based. The final determination will be made within 30 calendar days after presentation of additional information or arguments, or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(H) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the CAA.

(I) *Limitation on use of compliance extension.* The owner or operator may request an extension of compliance under the provisions specified in paragraph (b)(3)(ii) of this section only once for each facility.

(c) If you have an area source that does not commence reconstruction but increases its emissions or its potential to emit such that it becomes a major source of HAP emissions and an existing affected source subject to this subpart, you must be in compliance by 3 years after the area source becomes a major source.

(d) You must meet the notification requirements in §§63.2343 and 63.2382(a), as applicable, according to the schedules in §63.2382(a) and (b)(1) through (3) and in subpart A of this part. Some of these notifications must be submitted before the compliance dates for the emission limitations, operating limits, and work practice standards in this subpart.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42905, July 28, 2006]

[!\[\]\(3cb60d42b10e53f9522bb0b392c1c4cd_img.jpg\) Back to Top](#)

§63.2343 What are my requirements for emission sources not requiring control?

This section establishes the notification, recordkeeping, and reporting requirements for emission sources identified in §63.2338 that do not require control under this subpart (i.e., under paragraphs (a) through (e) of §63.2346). Such emission sources are not subject to any other notification, recordkeeping, or reporting sections in this subpart, including §63.2350(c), except as indicated in paragraphs (a) through (d) of this section.

(a) For each storage tank subject to this subpart having a capacity of less than 18.9 cubic meters (5,000 gallons) and for each transfer rack subject to this subpart that only unloads organic liquids (i.e., no organic liquids are loaded at any of the transfer racks), you must keep documentation that verifies that each storage tank and transfer rack identified in paragraph (a) of this section is not required to be controlled. The documentation must be kept up-to-date (i.e., all such emission sources at a facility are identified in the documentation regardless of when the documentation was last compiled) and must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form in a separate location. The documentation may consist of identification of the tanks and transfer racks identified in paragraph (a) of this section on a plant site plan or process and instrumentation diagram (P&ID).

(b) For each storage tank subject to this subpart having a capacity of 18.9 cubic meters (5,000 gallons) or more that is not subject to control based on the criteria specified in Table 2 to this subpart, items 1 through 6, you must comply with the requirements specified in paragraphs (b)(1) through (3) of this section.

(1)(i) You must submit the information in §63.2386(c)(1), (2), (3), and (10)(i) in either the Notification of Compliance Status, according to the schedule specified in Table 12 to this subpart, or in your first Compliance report, according to the schedule specified in §63.2386(b), whichever occurs first.

(ii)(A) If you submit your first Compliance report before your Notification of Compliance Status, the Notification of Compliance Status must contain the information specified in §63.2386(d)(3) and (4) if any of the changes identified in paragraph (d) of this section have occurred since the filing of the first Compliance report. If none of the changes identified in paragraph (d) of this section have occurred since the filing of the first Compliance report, you do not need to report the information specified in §63.2386(c)(10)(i) when you submit your Notification of Compliance Status.

(B) If you submit your Notification of Compliance Status before your first Compliance report, your first Compliance report must contain the information specified in §63.2386(d)(3) and (4) if any of the changes specified in paragraph (d) of this section have occurred since the filing of the Notification of Compliance Status.

(iii) If you are already submitting a Notification of Compliance Status or a first Compliance report under §63.2386(c), you do not need to submit a separate Notification of Compliance Status or first Compliance report for each storage tank that meets the conditions identified in paragraph (b) of this section (i.e., a single Notification of Compliance Status or first Compliance report should be submitted).

(2)(i) You must submit a subsequent Compliance report according to the schedule in §63.2386(b) whenever any of the events in paragraph (d) of this section occur, as applicable.

(ii) Your subsequent Compliance reports must contain the information in §63.2386(c)(1), (2), (3) and, as applicable, in §63.2386(d)(3) and (4). If you are already submitting a subsequent

Compliance report under §63.2386(d), you do not need to submit a separate subsequent Compliance report for each storage tank that meets the conditions identified in paragraph (b) of this section (i.e., a single subsequent Compliance report should be submitted).

(3) For each storage tank that meets the conditions identified in paragraph (b) of this section, you must keep documentation, including a record of the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid, that verifies the storage tank is not required to be controlled under this subpart. The documentation must be kept up-to-date and must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form in a separate location.

(c) For each transfer rack subject to this subpart that loads organic liquids but is not subject to control based on the criteria specified in Table 2 to this subpart, items 7 through 10, you must comply with the requirements specified in paragraphs (c)(1) through (3) of this section.

(1)(i) You must submit the information in §63.2386(c)(1), (2), (3), and (10)(i) in either the Notification of Compliance Status, according to the schedule specified in Table 12 to this subpart, or a first Compliance report, according to the schedule specified in §63.2386(b), whichever occurs first.

(ii)(A) If you submit your first Compliance report before your Notification of Compliance Status, the Notification of Compliance Status must contain the information specified in §63.2386(d)(3) and (4) if any of the changes identified in paragraph (d) of this section have occurred since the filing of the first Compliance report. If none of the changes identified in paragraph (d) of this section have occurred since the filing of the first Compliance report, you do not need to report the information specified in §63.2386(c)(10)(i) when you submit your Notification of Compliance Status.

(B) If you submit your Notification of Compliance Status before your first Compliance report, your first Compliance report must contain the information specified in §63.2386(d)(3) and (4) if any of the changes specified in paragraph (d) of this section have occurred since the filing of the Notification of Compliance Status.

(iii) If you are already submitting a Notification of Compliance Status or a first Compliance report under §63.2386(c), you do not need to submit a separate Notification of Compliance Status or first Compliance report for each transfer rack that meets the conditions identified in paragraph (b) of this section (i.e., a single Notification of Compliance Status or first Compliance report should be submitted).

(2)(i) You must submit a subsequent Compliance report according to the schedule in §63.2386(b) whenever any of the events in paragraph (d) of this section occur, as applicable.

(ii) Your subsequent Compliance reports must contain the information in §63.2386(c)(1), (2), (3) and, as applicable, in §63.2386(d)(3) and (4). If you are already submitting a subsequent Compliance report under §63.2386(d), you do not need to submit a separate subsequent

Compliance report for each transfer rack that meets the conditions identified in paragraph (c) of this section (i.e., a single subsequent Compliance report should be submitted).

(3) For each transfer rack that meets the conditions identified in paragraph (c) of this section, you must keep documentation, including the records specified in §63.2390(d), that verifies the transfer rack is not required to be controlled under this subpart. The documentation must be kept up-to-date and must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form in a separate location.

(d) If one or more of the events identified in paragraphs (d)(1) through (4) of this section occur since the filing of the Notification of Compliance Status or the last Compliance report, you must submit a subsequent Compliance report as specified in paragraphs (b)(2) and (c)(2) of this section.

(1) Any storage tank or transfer rack became subject to control under this subpart EEEE; or

(2) Any storage tank equal to or greater than 18.9 cubic meters (5,000 gallons) became part of the affected source but is not subject to any of the emission limitations, operating limits, or work practice standards of this subpart; or

(3) Any transfer rack (except those racks at which only unloading of organic liquids occurs) became part of the affected source; or

(4) Any of the information required in §63.2386(c)(1), §63.2386(c)(2), or §63.2386(c)(3) has changed.

[71 FR 42906, July 28, 2006, as amended at 73 FR 21830, Apr. 23, 2008]

[↑ Back to Top](#)

Emission Limitations, Operating Limits, and Work Practice Standards

[↑ Back to Top](#)

§63.2346 What emission limitations, operating limits, and work practice standards must I meet?

(a) *Storage tanks.* For each storage tank storing organic liquids that meets the tank capacity and liquid vapor pressure criteria for control in Table 2 to this subpart, items 1 through 5, you must comply with paragraph (a)(1), (a)(2), (a)(3), or (a)(4) of this section. For each storage tank storing organic liquids that meets the tank capacity and liquid vapor pressure criteria for control

in Table 2 to this subpart, item 6, you must comply with paragraph (a)(1), (a)(2), or (a)(4) of this section.

(1) Meet the emission limits specified in Table 2 to this subpart and comply with the applicable requirements specified in 40 CFR part 63, subpart SS, for meeting emission limits, except substitute the term “storage tank” at each occurrence of the term “storage vessel” in subpart SS.

(2) Route emissions to fuel gas systems or back into a process as specified in 40 CFR part 63, subpart SS.

(3) Comply with 40 CFR part 63, subpart WW (control level 2).

(4) Use a vapor balancing system that complies with the requirements specified in paragraphs (a)(4)(i) through (vii) of this section and with the recordkeeping requirements specified in §63.2390(e).

(i) The vapor balancing system must be designed and operated to route organic HAP vapors displaced from loading of the storage tank to the transport vehicle from which the storage tank is filled.

(ii) Transport vehicles must have a current certification in accordance with the United States Department of Transportation (U.S. DOT) pressure test requirements of 49 CFR part 180 for cargo tanks and 49 CFR 173.31 for tank cars.

(iii) Organic liquids must only be unloaded from cargo tanks or tank cars when vapor collection systems are connected to the storage tank's vapor collection system.

(iv) No pressure relief device on the storage tank, or on the cargo tank or tank car, shall open during loading or as a result of diurnal temperature changes (breathing losses).

(v) Pressure relief devices must be set to no less than 2.5 pounds per square inch gauge (psig) at all times to prevent breathing losses. Pressure relief devices may be set at values less than 2.5 psig if the owner or operator provides rationale in the notification of compliance status report explaining why the alternative value is sufficient to prevent breathing losses at all times. The owner or operator shall comply with paragraphs (a)(4)(v)(A) through (C) of this section for each pressure relief valve.

(A) The pressure relief valve shall be monitored quarterly using the method described in §63.180(b).

(B) An instrument reading of 500 parts per million by volume (ppmv) or greater defines a leak.

(C) When a leak is detected, it shall be repaired as soon as practicable, but no later than 5 days after it is detected, and the owner or operator shall comply with the recordkeeping requirements of §63.181(d)(1) through (4).

(vi) Cargo tanks and tank cars that deliver organic liquids to a storage tank must be reloaded or cleaned at a facility that utilizes the control techniques specified in paragraph (a)(4)(vi)(A) or (a)(4)(vi)(B) of this section.

(A) The cargo tank or tank car must be connected to a closed-vent system with a control device that reduces inlet emissions of total organic HAP by 95 percent by weight or greater or to an exhaust concentration less than or equal to 20 ppmv, on a dry basis corrected to 3 percent oxygen for combustion devices using supplemental combustion air.

(B) A vapor balancing system designed and operated to collect organic HAP vapor displaced from the cargo tank or tank car during reloading must be used to route the collected vapor to the storage tank from which the liquid being transferred originated or to another storage tank connected to a common header.

(vii) The owner or operator of the facility where the cargo tank or tank car is reloaded or cleaned must comply with paragraphs (a)(4)(vii)(A) through (D) of this section.

(A) Submit to the owner or operator of the storage tank and to the Administrator a written certification that the reloading or cleaning facility will meet the requirements of paragraph (a)(4)(vii)(A) through (C) of this section. The certifying entity may revoke the written certification by sending a written statement to the owner or operator of the storage tank giving at least 90 days notice that the certifying entity is rescinding acceptance of responsibility for compliance with the requirements of this paragraph (a)(4)(vii) of this section.

(B) If complying with paragraph (a)(4)(vi)(A) of this section, comply with the requirements for a closed vent system and control device as specified in this subpart EEEE. The notification requirements in §63.2382 and the reporting requirements in §63.2386 do not apply to the owner or operator of the offsite cleaning or reloading facility.

(C) If complying with paragraph (a)(4)(vi)(B) of this section, keep the records specified in §63.2390(e)(3) or equivalent recordkeeping approved by the Administrator.

(D) After the compliance dates specified in §63.2342, at an offsite reloading or cleaning facility subject to §63.2346(a)(4), compliance with the monitoring, recordkeeping, and reporting provisions of any other subpart of this part 63 that has monitoring, recordkeeping, and reporting provisions constitutes compliance with the monitoring, recordkeeping and reporting provisions of §63.2346(a)(4)(vii)(B) or §63.2346(a)(4)(vii)(C). You must identify in your notification of compliance status report required by §63.2382(d) the subpart of this part 63 with which the owner or operator of the offsite reloading or cleaning facility complies.

(b) *Transfer racks.* For each transfer rack that is part of the collection of transfer racks that meets the total actual annual facility-level organic liquid loading volume criterion for control in Table 2 to this subpart, items 7 through 10, you must comply with paragraph (b)(1), (b)(2), or (b)(3) of this section for each arm in the transfer rack loading an organic liquid whose organic HAP content meets the organic HAP criterion for control in Table 2 to this subpart, items 7 through 10. For existing affected sources, you must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) of

this section during the loading of organic liquids into transport vehicles. For new affected sources, you must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) and (ii) of this section during the loading of organic liquids into transport vehicles and containers. If the total actual annual facility-level organic liquid loading volume at any affected source is equal to or greater than the loading volume criteria for control in Table 2 to this subpart, but at a later date is less than the loading volume criteria for control, compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is no longer required. For new sources and reconstructed sources, as defined in §63.2338(d) and (e), if at a later date, the total actual annual facility-level organic liquid loading volume again becomes equal to or greater than the loading volume criteria for control in Table 2 to this subpart, the owner or operator must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) and (ii) of this section immediately, as specified in §63.2342(a)(3). For existing sources, as defined in §63.2338(f), if at a later date, the total actual annual facility-level organic liquid loading volume again becomes equal to or greater than the loading volume criteria for control in Table 2 to this subpart, the owner or operator must comply with paragraph (b)(1), (b)(2), or (b)(3)(i) of this section immediately, as specified in §63.2342(b)(3)(i), unless an alternative compliance schedule has been approved under §63.2342(b)(3)(ii) and subject to the use limitation specified in §63.2342(b)(3)(ii)(I).

(1) Meet the emission limits specified in Table 2 to this subpart and comply with the applicable requirements for transfer racks specified in 40 CFR part 63, subpart SS, for meeting emission limits.

(2) Route emissions to fuel gas systems or back into a process as specified in 40 CFR part 63, subpart SS.

(3)(i) Use a vapor balancing system that routes organic HAP vapors displaced from the loading of organic liquids into transport vehicles to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header.

(ii) Use a vapor balancing system that routes the organic HAP vapors displaced from the loading of organic liquids into containers directly (e.g., no intervening tank or containment area such as a room) to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header.

(c) *Equipment leak components.* For each pump, valve, and sampling connection that operates in organic liquids service for at least 300 hours per year, you must comply with the applicable requirements under 40 CFR part 63, subpart TT (control level 1), subpart UU (control level 2), or subpart H. Pumps, valves, and sampling connectors that are insulated to provide protection against persistent sub-freezing temperatures are subject to the “difficult to monitor” provisions in the applicable subpart selected by the owner or operator. This paragraph only applies if the affected source has at least one storage tank or transfer rack that meets the applicability criteria for control in Table 2 to this subpart.

(d) *Transport vehicles.* For each transport vehicle equipped with vapor collection equipment that is loaded at a transfer rack that is subject to control based on the criteria specified in Table 2 to this subpart, items 7 through 10, you must comply with paragraph (d)(1) of this section. For each

transport vehicle without vapor collection equipment that is loaded at a transfer rack that is subject to control based on the criteria specified in Table 2 to this subpart, items 7 through 10, you must comply with paragraph (d)(2) of this section.

(1) Follow the steps in 40 CFR 60.502(e) to ensure that organic liquids are loaded only into vapor-tight transport vehicles and comply with the provisions in 40 CFR 60.502(f) through (i), except substitute the term “transport vehicle” at each occurrence of the term “tank truck” or “gasoline tank truck” in those paragraphs.

(2) Ensure that organic liquids are loaded only into transport vehicles that have a current certification in accordance with the U.S. Department of Transportation (DOT) pressure test requirements in 49 CFR part 180 for cargo tanks or 49 CFR 173.31 for tank cars.

(e) *Operating limits.* For each high throughput transfer rack, you must meet each operating limit in Table 3 to this subpart for each control device used to comply with the provisions of this subpart whenever emissions from the loading of organic liquids are routed to the control device. For each storage tank and low throughput transfer rack, you must comply with the requirements for monitored parameters as specified in subpart SS of this part for storage vessels and, during the loading of organic liquids, for low throughput transfer racks, respectively. Alternatively, you may comply with the operating limits in Table 3 to this subpart.

(f) For noncombustion devices, if you elect to demonstrate compliance with a percent reduction requirement in Table 2 to this subpart using total organic compounds (TOC) rather than organic HAP, you must first demonstrate, subject to the approval of the Administrator, that TOC is an appropriate surrogate for organic HAP in your case; that is, for your storage tank(s) and/or transfer rack(s), the percent destruction of organic HAP is equal to or higher than the percent destruction of TOC. This demonstration must be conducted prior to or during the initial compliance test.

(g) As provided in §63.6(g), you may request approval from the Administrator to use an alternative to the emission limitations, operating limits, and work practice standards in this section. You must follow the procedures in §63.177(b) through (e) in applying for permission to use such an alternative. If you apply for permission to use an alternative to the emission limitations, operating limits, and work practice standards in this section, you must submit the information described in §63.6(g)(2).

(h) [Reserved]

(i) Opening of a safety device is allowed at any time that it is required to avoid unsafe operating conditions.

(j) If you elect to comply with this subpart by combining emissions from different emission sources subject to this subpart in a single control device, then you must comply with the provisions specified in §63.982(f).

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42908, July 28, 2006; 73 FR 40981, July 17, 2008; 73 FR 21830, Apr. 23, 2008]

[↑ Back to Top](#)

General Compliance Requirements

[↑ Back to Top](#)

§63.2350 What are my general requirements for complying with this subpart?

- (a) You must be in compliance with the emission limitations, operating limits, and work practice standards in this subpart at all times when the equipment identified in §63.2338(b)(1) through (4) is in OLD operation.
- (b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).
- (c) Except for emission sources not required to be controlled as specified in §63.2343, you must develop a written startup, shutdown, and malfunction (SSM) plan according to the provisions in §63.6(e)(3).

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42909, July 28, 2006]

[↑ Back to Top](#)

Testing and Initial Compliance Requirements

[↑ Back to Top](#)

§63.2354 What performance tests, design evaluations, and performance evaluations must I conduct?

- (a)(1) For each performance test that you conduct, you must use the procedures specified in subpart SS of this part and the provisions specified in paragraph (b) of this section.
- (2) For each design evaluation you conduct, you must use the procedures specified in subpart SS of this part.
- (3) For each performance evaluation of a continuous emission monitoring system (CEMS) you conduct, you must follow the requirements in §63.8(e).

(b)(1) For nonflare control devices, you must conduct each performance test according to the requirements in §63.7(e)(1), and either §63.988(b), §63.990(b), or §63.995(b), using the procedures specified in §63.997(e).

(2) You must conduct three separate test runs for each performance test on a nonflare control device as specified in §§63.7(e)(3) and 63.997(e)(1)(v). Each test run must last at least 1 hour, except as provided in §63.997(e)(1)(v)(A) and (B).

(3)(i) In addition to EPA Method 25 or 25A of 40 CFR part 60, appendix A, to determine compliance with the organic HAP or TOC emission limit, you may use EPA Method 18 of 40 CFR part 60, appendix A, as specified in paragraph (b)(3)(i) of this section. As an alternative to EPA Method 18, you may use ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), under the conditions specified in paragraph (b)(3)(ii) of this section.

(A) If you use EPA Method 18 to measure compliance with the percentage efficiency limit, you must first determine which organic HAP are present in the inlet gas stream (i.e., uncontrolled emissions) using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, you must analyze samples collected as specified in EPA Method 18, simultaneously at the inlet and outlet of the control device. Quantify the emissions for the same organic HAP identified as present in the inlet gas stream for both the inlet and outlet gas streams of the control device.

(B) If you use EPA Method 18 of 40 CFR part 60, appendix A, to measure compliance with the emission concentration limit, you must first determine which organic HAP are present in the inlet gas stream using knowledge of the organic liquids or the screening procedure described in EPA Method 18. In conducting the performance test, analyze samples collected as specified in EPA Method 18 at the outlet of the control device. Quantify the control device outlet emission concentration for the same organic HAP identified as present in the inlet or uncontrolled gas stream.

(ii) You may use ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), as an alternative to EPA Method 18 if the target concentration is between 150 parts per billion by volume and 100 ppmv and either of the conditions specified in paragraph (b)(2)(ii)(A) or (B) of this section exists. For target compounds not listed in Section 1.1 of ASTM D6420-99 (Reapproved 2004) and not amenable to detection by mass spectrometry, you may not use ASTM D6420-99 (Reapproved 2004).

(A) The target compounds are those listed in Section 1.1 of ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14),; or

(B) For target compounds not listed in Section 1.1 of ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface

Gas Chromatography-Mass Spectrometry (incorporated by reference, see §63.14), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in ASTM D6420-99 (Reapproved 2004), Section 10.5.3, must be followed, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water-soluble.

(4) If a principal component of the uncontrolled or inlet gas stream to the control device is formaldehyde, you may use EPA Method 316 of appendix A of this part instead of EPA Method 18 of 40 CFR part 60, appendix A, for measuring the formaldehyde. If formaldehyde is the predominant organic HAP in the inlet gas stream, you may use EPA Method 316 alone to measure formaldehyde either at the inlet and outlet of the control device using the formaldehyde control efficiency as a surrogate for total organic HAP or TOC efficiency, or at the outlet of a combustion device for determining compliance with the emission concentration limit.

(5) You may not conduct performance tests during periods of SSM, as specified in §63.7(e)(1).

(c) To determine the HAP content of the organic liquid, you may use EPA Method 311 of 40 CFR part 63, appendix A, or other method approved by the Administrator. In addition, you may use other means, such as voluntary consensus standards, material safety data sheets (MSDS), or certified product data sheets, to determine the HAP content of the organic liquid. If the method you select to determine the HAP content provides HAP content ranges, you must use the upper end of each HAP content range in determining the total HAP content of the organic liquid. The EPA may require you to test the HAP content of an organic liquid using EPA Method 311 or other method approved by the Administrator. If the results of the EPA Method 311 (or any other approved method) are different from the HAP content determined by another means, the EPA Method 311 (or approved method) results will govern.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42909, July 28, 2006]

[↑ Back to Top](#)

§63.2358 By what date must I conduct performance tests and other initial compliance demonstrations?

(a) You must conduct initial performance tests and design evaluations according to the schedule in §63.7(a)(2), or by the compliance date specified in any applicable State or Federal new source review construction permit to which the affected source is already subject, whichever is earlier.

(b)(1) For storage tanks and transfer racks at existing affected sources complying with the emission limitations listed in Table 2 to this subpart, you must demonstrate initial compliance with the emission limitations within 180 days after February 5, 2007, except as provided in paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(i) For storage tanks with an existing internal or external floating roof, complying with item 1.a.ii. in Table 2 to this subpart and item 1.a. in Table 4 to this subpart, you must conduct your

initial compliance demonstration the next time the storage tank is emptied and degassed, but not later than February 3, 2014.

(ii) For storage tanks complying with item 1.a.ii. or 6.a.ii in Table 2 of this subpart and item 1.b., 1.c., or 2. in Table 4 of this subpart, you must comply within 180 days after April 25, 2011.

(2) For storage tanks and transfer racks at reconstructed or new affected sources complying with the emission limitations listed in Table 2 to this subpart, you must conduct your initial compliance demonstration with the emission limitations within 180 days after the initial startup date for the affected source or February 3, 2004, whichever is later.

(c)(1) For storage tanks at existing affected sources complying with the work practice standard in Table 4 to this subpart, you must conduct your initial compliance demonstration as specified in paragraphs (c)(1)(i) and (c)(1)(ii) of this section.

(i) For storage tanks with an existing internal or external floating roof, complying with item 1.a. in Table 4 of this subpart, you must conduct your initial compliance demonstration the next time the storage tank is emptied and degassed, but not later than February 3, 2014.

(ii) For other storage tanks not specified in paragraph (c)(1)(i) of this section, you must comply within 180 days after April 25, 2011.

(2) For transfer racks and equipment leak components at existing affected sources complying with the work practice standards in Table 4 to this subpart, you must conduct your initial compliance demonstration within 180 days after February 5, 2007.

(d) For storage tanks, transfer racks, and equipment leak components at reconstructed or new affected sources complying with the work practice standards in Table 4 to this subpart, you must conduct your initial compliance demonstration within 180 days after the initial startup date for the affected source.

[69 FR 5063, Feb. 3, 2004, as amended at 73 FR 40981, July 17, 2008]

[↑ Back to Top](#)

§63.2362 When must I conduct subsequent performance tests?

(a) For nonflare control devices, you must conduct subsequent performance testing required in Table 5 to this subpart, item 1, at any time the EPA requests you to in accordance with section 114 of the CAA.

(b)(1) For each transport vehicle that you own that is equipped with vapor collection equipment and that is loaded with organic liquids at a transfer rack that is subject to control based on the criteria specified in Table 2 to this subpart, items 7 through 10, you must perform the vapor

tightness testing required in Table 5 to this subpart, item 2, on that transport vehicle at least once per year.

(2) For transport vehicles that you own that do not have vapor collection equipment, you must maintain current certification in accordance with the U.S. DOT pressure test requirements in 49 CFR part 180 for cargo tanks or 49 CFR 173.31 for tank cars.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42910, July 28, 2006]

[↑ Back to Top](#)

§63.2366 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain a CMS on each control device required in order to comply with this subpart. If you use a continuous parameter monitoring system (CPMS) (as defined in §63.981), you must comply with the applicable requirements for CPMS in subpart SS of this part for the control device being used. If you use a continuous emissions monitoring system (CEMS), you must comply with the requirements in §63.8.

(b) For nonflare control devices controlling storage tanks and low throughput transfer racks, you must submit a monitoring plan according to the requirements in subpart SS of this part for monitoring plans.

[↑ Back to Top](#)

§63.2370 How do I demonstrate initial compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate initial compliance with each emission limitation and work practice standard that applies to you as specified in tables 6 and 7 to this subpart.

(b) You demonstrate initial compliance with the operating limits requirements specified in §63.2346(e) by establishing the operating limits during the initial performance test or design evaluation.

(c) You must submit the results of the initial compliance determination in the Notification of Compliance Status according to the requirements in §63.2382(d).

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42910, July 28, 2006]

[↑ Back to Top](#)

Continuous Compliance Requirements

[↑ Back to Top](#)

§63.2374 When do I monitor and collect data to demonstrate continuous compliance and how do I use the collected data?

- (a) You must monitor and collect data according to subpart SS of this part and paragraphs (b) and (c) of this section.
- (b) When using a control device to comply with this subpart, you must monitor continuously or collect data at all required intervals at all times that the emission source and control device are in OLD operation, except for CMS malfunctions (including any malfunction preventing the CMS from operating properly), associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments).
- (c) Do not use data recorded during CMS malfunctions, associated repairs, required quality assurance or control activities, or periods when emissions from organic liquids are not routed to the control device in data averages and calculations used to report emission or operating levels. Do not use such data in fulfilling a minimum data availability requirement, if applicable. You must use all of the data collected during all other periods, including periods of SSM, in assessing the operation of the control device.

[↑ Back to Top](#)

§63.2378 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

- (a) You must demonstrate continuous compliance with each emission limitation, operating limit, and work practice standard in Tables 2 through 4 to this subpart that applies to you according to the methods specified in subpart SS of this part and in tables 8 through 10 to this subpart, as applicable.
- (b) You must follow the requirements in §63.6(e)(1) and (3) during periods of startup, shutdown, malfunction, or nonoperation of the affected source or any part thereof. In addition, the provisions of paragraphs (b)(1) through (3) of this section apply.
 - (1) The emission limitations in this subpart apply at all times except during periods of nonoperation of the affected source (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies. The emission limitations of this subpart apply during periods of SSM, except as provided in paragraphs (b)(2) and (3) of this section. However, if a

SSM, or period of nonoperation of one portion of the affected source does not affect the ability of a particular emission source to comply with the emission limitations to which it is subject, then that emission source is still required to comply with the applicable emission limitations of this subpart during the startup, shutdown, malfunction, or period of nonoperation.

(2) The owner or operator must not shut down control devices or monitoring systems that are required or utilized for achieving compliance with this subpart during periods of SSM while emissions are being routed to such items of equipment if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph (b)(2) does not apply if the item of equipment is malfunctioning. This paragraph (b)(2) also does not apply if the owner or operator shuts down the compliance equipment (other than monitoring systems) to avoid damage due to a contemporaneous SSM of the affected source or portion thereof. If the owner or operator has reason to believe that monitoring equipment would be damaged due to a contemporaneous SSM of the affected source or portion thereof, the owner or operator must provide documentation supporting such a claim in the next Compliance report required in table 11 to this subpart, item 1. Once approved by the Administrator, the provision for ceasing to collect, during a SSM, monitoring data that would otherwise be required by the provisions of this subpart must be incorporated into the SSM plan.

(3) During SSM, you must implement, to the extent reasonably available, measures to prevent or minimize excess emissions. For purposes of this paragraph (b)(3), the term “excess emissions” means emissions greater than those allowed by the emission limits that apply during normal operational periods. The measures to be taken must be identified in the SSM plan, and may include, but are not limited to, air pollution control technologies, recovery technologies, work practices, pollution prevention, monitoring, and/or changes in the manner of operation of the affected source. Back-up control devices are not required, but may be used if available.

(c) Periods of planned routine maintenance of a control device used to control storage tanks or transfer racks, during which the control device does not meet the emission limits in table 2 to this subpart, must not exceed 240 hours per year.

(d) If you elect to route emissions from storage tanks or transfer racks to a fuel gas system or to a process, as allowed by §63.982(d), to comply with the emission limits in table 2 to this subpart, the total aggregate amount of time during which the emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except SSM or product changeovers of flexible operation units and periods when a storage tank has been emptied and degassed), must not exceed 240 hours.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 20463, Apr. 20, 2006]

[!\[\]\(0aff635c4179ba9e710b00f4b01d3b20_img.jpg\) Back to Top](#)

Notifications, Reports, and Records

[!\[\]\(0b5e7e25e8775f7e7e80906ada4f0021_img.jpg\) Back to Top](#)

§63.2382 What notifications must I submit and when and what information should be submitted?

(a) You must submit each notification in subpart SS of this part, table 12 to this subpart, and paragraphs (b) through (d) of this section that applies to you. You must submit these notifications according to the schedule in table 12 to this subpart and as specified in paragraphs (b) through (d) of this section.

(b)(1) *Initial Notification.* If you startup your affected source before February 3, 2004, you must submit the Initial Notification no later than 120 calendar days after February 3, 2004.

(2) If you startup your new or reconstructed affected source on or after February 3, 2004, you must submit the Initial Notification no later than 120 days after initial startup.

(c) If you are required to conduct a performance test, you must submit the Notification of Intent to conduct the test at least 60 calendar days before it is initially scheduled to begin as required in §63.7(b)(1).

(d)(1) *Notification of Compliance Status.* If you are required to conduct a performance test, design evaluation, or other initial compliance demonstration as specified in table 5, 6, or 7 to this subpart, you must submit a Notification of Compliance Status.

(2) The Notification of Compliance Status must include the information required in §63.999(b) and in paragraphs (d)(2)(i) through (viii) of this section.

(i) The results of any applicability determinations, emission calculations, or analyses used to identify and quantify organic HAP emissions from the affected source.

(ii) The results of emissions profiles, performance tests, engineering analyses, design evaluations, flare compliance assessments, inspections and repairs, and calculations used to demonstrate initial compliance according to tables 6 and 7 to this subpart. For performance tests, results must include descriptions of sampling and analysis procedures and quality assurance procedures.

(iii) Descriptions of monitoring devices, monitoring frequencies, and the operating limits established during the initial compliance demonstrations, including data and calculations to support the levels you establish.

(iv) Descriptions of worst-case operating and/or testing conditions for the control device(s).

(v) Identification of emission sources subject to overlapping requirements described in §63.2396 and the authority under which you will comply.

(vi) The applicable information specified in §63.1039(a)(1) through (3) for all pumps and valves subject to the work practice standards for equipment leak components in table 4 to this subpart, item 4.

(vii) If you are complying with the vapor balancing work practice standard for transfer racks according to table 4 to this subpart, item 3.a, include a statement to that effect and a statement that the pressure vent settings on the affected storage tanks are greater than or equal to 2.5 psig.

(viii) The information specified in §63.2386(c)(10)(i), unless the information has already been submitted with the first Compliance report. If the information specified in §63.2386(c)(10)(i) has already been submitted with the first Compliance report, the information specified in §63.2386(d)(3) and (4), as applicable, shall be submitted instead.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42910, July 28, 2006]

[↑ Back to Top](#)

§63.2386 What reports must I submit and when and what information is to be submitted in each?

(a) You must submit each report in subpart SS of this part, Table 11 to this subpart, table 12 to this subpart, and in paragraphs (c) through (e) of this section that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report according to table 11 to this subpart and by the dates shown in paragraphs (b)(1) through (3) of this section, by the dates shown in subpart SS of this part, and by the dates shown in table 12 to this subpart, whichever are applicable.

(1)(i) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.2342 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(ii) The first Compliance report must be postmarked no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.2342.

(2)(i) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(ii) Each subsequent Compliance report must be postmarked no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(3) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, if the permitting authority has established dates for submitting semiannual

reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) and (2) of this section.

(c) *First Compliance report.* The first Compliance report must contain the information specified in paragraphs (c)(1) through (10) of this section.

(1) Company name and address.

(2) Statement by a responsible official, including the official's name, title, and signature, certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

(3) Date of report and beginning and ending dates of the reporting period.

(4) Any changes to the information listed in §63.2382(d)(2) that have occurred since the submittal of the Notification of Compliance Status.

(5) If you had a SSM during the reporting period and you took actions consistent with your SSM plan, the Compliance report must include the information described in §63.10(d)(5)(i).

(6) If there are no deviations from any emission limitation or operating limit that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations, operating limits, or work practice standards during the reporting period.

(7) If there were no periods during which the CMS was out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out of control during the reporting period.

(8) For closed vent systems and control devices used to control emissions, the information specified in paragraphs (c)(8)(i) and (ii) of this section for those planned routine maintenance activities that would require the control device to not meet the applicable emission limit.

(i) A description of the planned routine maintenance that is anticipated to be performed for the control device during the next 6 months. This description must include the type of maintenance necessary, planned frequency of maintenance, and lengths of maintenance periods.

(ii) A description of the planned routine maintenance that was performed for the control device during the previous 6 months. This description must include the type of maintenance performed and the total number of hours during those 6 months that the control device did not meet the applicable emission limit due to planned routine maintenance.

(9) A listing of all transport vehicles into which organic liquids were loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10,

during the previous 6 months for which vapor tightness documentation as required in §63.2390(c) was not on file at the facility.

(10)(i) A listing of all transfer racks (except those racks at which only unloading of organic liquids occurs) and of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that are part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart.

(ii) If the information specified in paragraph (c)(10)(i) of this section has already been submitted with the Notification of Compliance Status, the information specified in paragraphs (d)(3) and (4) of this section, as applicable, shall be submitted instead.

(d) *Subsequent Compliance reports.* Subsequent Compliance reports must contain the information in paragraphs (c)(1) through (9) of this section and, where applicable, the information in paragraphs (d)(1) through (4) of this section.

(1) For each deviation from an emission limitation occurring at an affected source where you are using a CMS to comply with an emission limitation in this subpart, you must include in the Compliance report the applicable information in paragraphs (d)(1)(i) through (xii) of this section. This includes periods of SSM.

(i) The date and time that each malfunction started and stopped.

(ii) The dates and times that each CMS was inoperative, except for zero (low-level) and high-level checks.

(iii) For each CMS that was out of control, the information in §63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of SSM, or during another period.

(v) A summary of the total duration of the deviations during the reporting period, and the total duration as a percentage of the total emission source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percentage of the total emission source operating time during that reporting period.

(viii) An identification of each organic HAP that was potentially emitted during each deviation based on the known organic HAP contained in the liquid(s).

(ix) A brief description of the emission source(s) at which the CMS deviation(s) occurred.

(x) A brief description of each CMS that was out of control during the period.

(xi) The date of the latest certification or audit for each CMS.

(xii) A brief description of any changes in CMS, processes, or controls since the last reporting period.

(2) Include in the Compliance report the information in paragraphs (d)(2)(i) through (iii) of this section, as applicable.

(i) For each storage tank and transfer rack subject to control requirements, include periods of planned routine maintenance during which the control device did not comply with the applicable emission limits in table 2 to this subpart.

(ii) For each storage tank controlled with a floating roof, include a copy of the inspection record (required in §63.1065(b)) when inspection failures occur.

(iii) If you elect to use an extension for a floating roof inspection in accordance with §63.1063(c)(2)(iv)(B) or (e)(2), include the documentation required by those paragraphs.

(3)(i) A listing of any storage tank that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 1 through 6, since the filing of the last Compliance report.

(ii) A listing of any transfer rack that became subject to controls based on the criteria for control specified in table 2 to this subpart, items 7 through 10, since the filing of the last Compliance report.

(4)(i) A listing of tanks greater than or equal to 18.9 cubic meters (5,000 gallons) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(ii) A listing of all transfer racks (except those racks at which only the unloading of organic liquids occurs) that became part of the affected source but are not subject to any of the emission limitations, operating limits, or work practice standards of this subpart, since the last Compliance report.

(e) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 11 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission limitation in this subpart, we will consider submission of the Compliance report as satisfying any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report will not otherwise affect any obligation the

affected source may have to report deviations from permit requirements to the applicable title V permitting authority.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42910, July 28, 2006]

[↑ Back to Top](#)

§63.2390 What records must I keep?

(a) For each emission source identified in §63.2338 that does not require control under this subpart, you must keep all records identified in §63.2343.

(b) For each emission source identified in §63.2338 that does require control under this subpart:

(1) You must keep all records identified in subpart SS of this part and in table 12 to this subpart that are applicable, including records related to notifications and reports, SSM, performance tests, CMS, and performance evaluation plans; and

(2) You must keep the records required to show continuous compliance, as required in subpart SS of this part and in tables 8 through 10 to this subpart, with each emission limitation, operating limit, and work practice standard that applies to you.

(c) For each transport vehicle into which organic liquids are loaded at a transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, you must keep the applicable records in paragraphs (c)(1) and (2) of this section or alternatively the verification records in paragraph (c)(3) of this section.

(1) For transport vehicles equipped with vapor collection equipment, the documentation described in 40 CFR 60.505(b), except that the test title is: Transport Vehicle Pressure Test-EPA Reference Method 27.

(2) For transport vehicles without vapor collection equipment, current certification in accordance with the U.S. DOT pressure test requirements in 49 CFR part 180 for cargo tanks or 49 CFR 173.31 for tank cars.

(3) In lieu of keeping the records specified in paragraph (c)(1) or (2) of this section, as applicable, the owner or operator shall record that the verification of U.S. DOT tank certification or Method 27 of appendix A to 40 CFR part 60 testing, required in table 5 to this subpart, item 2, has been performed. Various methods for the record of verification can be used, such as: A check-off on a log sheet, a list of U.S. DOT serial numbers or Method 27 data, or a position description for gate security showing that the security guard will not allow any trucks on site that do not have the appropriate documentation.

(d) You must keep records of the total actual annual facility-level organic liquid loading volume as defined in §63.2406 through transfer racks to document the applicability, or lack thereof, of the emission limitations in table 2 to this subpart, items 7 through 10.

(e) An owner or operator who elects to comply with §63.2346(a)(4) shall keep the records specified in paragraphs (e)(1) through (3) of this section.

(1) A record of the U.S. DOT certification required by §63.2346(a)(4)(ii).

(2) A record of the pressure relief vent setting specified in §63.2346(a)(4)(v).

(3) If complying with §63.2346(a)(4)(vi)(B), keep the records specified in paragraphs (e)(3)(i) and (ii) of this section.

(i) A record of the equipment to be used and the procedures to be followed when reloading the cargo tank or tank car and displacing vapors to the storage tank from which the liquid originates.

(ii) A record of each time the vapor balancing system is used to comply with §63.2346(a)(4)(vi)(B).

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42910, July 28, 2006; 73 FR 40982, July 17, 2008]

[!\[\]\(ec9132f1d27c8919987d92907322654d_img.jpg\) Back to Top](#)

§63.2394 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious inspection and review according to §63.10(b)(1), including records stored in electronic form at a separate location.

(b) As specified in §63.10(b)(1), you must keep your files of all information (including all reports and notifications) for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You may keep the records off site for the remaining 3 years.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42911, July 28, 2006]

[!\[\]\(626ce8ac21792b9405bfddfea8e0c96a_img.jpg\) Back to Top](#)

Other Requirements and Information

[!\[\]\(248b91fcdac4810ffd15cf33fb6aec6f_img.jpg\) Back to Top](#)

§63.2396 What compliance options do I have if part of my plant is subject to both this subpart and another subpart?

(a) *Compliance with other regulations for storage tanks.* (1) After the compliance dates specified in §63.2342, you are in compliance with the provisions of this subpart for any storage tank that is assigned to the OLD affected source and that is both controlled with a floating roof and is in compliance with the provisions of either 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y, except that records shall be kept for 5 years rather than 2 years for storage tanks that are assigned to the OLD affected source.

(2) After the compliance dates specified in §63.2342, you are in compliance with the provisions of this subpart for any storage tank with a fixed roof that is assigned to the OLD affected source and that is both controlled with a closed vent system and control device and is in compliance with either 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y, except that you must comply with the monitoring, recordkeeping, and reporting requirements in this subpart.

(3) As an alternative to paragraphs (a)(1) and (2) of this section, if a storage tank assigned to the OLD affected source is subject to control under 40 CFR part 60, subpart Kb, or 40 CFR part 61, subpart Y, you may elect to comply only with the requirements of this subpart for storage tanks meeting the applicability criteria for control in table 2 to this subpart.

(b) *Compliance with other regulations for transfer racks.* After the compliance dates specified in §63.2342, if you have a transfer rack that is subject to 40 CFR part 61, subpart BB, and that transfer rack is in OLD operation, you must meet all of the requirements of this subpart for that transfer rack when the transfer rack is in OLD operation during the loading of organic liquids.

(c) *Compliance with other regulations for equipment leak components.* (1) After the compliance dates specified in §63.2342, if you have pumps, valves, or sampling connections that are subject to a 40 CFR part 60 subpart, and those pumps, valves, and sampling connections are in OLD operation and in organic liquids service, as defined in this subpart, you must comply with the provisions of each subpart for those equipment leak components.

(2) After the compliance dates specified in §63.2342, if you have pumps, valves, or sampling connections subject to 40 CFR part 63, subpart GGG, and those pumps, valves, and sampling connections are in OLD operation and in organic liquids service, as defined in this subpart, you may elect to comply with the provisions of this subpart for all such equipment leak components. You must identify in the Notification of Compliance Status required by §63.2382(b) the provisions with which you will comply.

(d) [Reserved]

(e) *Overlap with other regulations for monitoring, recordkeeping, and reporting—*(1) *Control devices.* After the compliance dates specified in §63.2342, if any control device subject to this subpart is also subject to monitoring, recordkeeping, and reporting requirements of another 40 CFR part 63 subpart, the owner or operator must be in compliance with the monitoring,

recordkeeping, and reporting requirements of this subpart EEEE. If complying with the monitoring, recordkeeping, and reporting requirements of the other subpart satisfies the monitoring, recordkeeping, and reporting requirements of this subpart, the owner or operator may elect to continue to comply with the monitoring, recordkeeping, and reporting requirements of the other subpart. In such instances, the owner or operator will be deemed to be in compliance with the monitoring, recordkeeping, and reporting requirements of this subpart. The owner or operator must identify the other subpart being complied with in the Notification of Compliance Status required by §63.2382(b).

(2) *Equipment leak components.* After the compliance dates specified in §63.2342, if you are applying the applicable recordkeeping and reporting requirements of another 40 CFR part 63 subpart to the valves, pumps, and sampling connection systems associated with a transfer rack subject to this subpart that only unloads organic liquids directly to or via pipeline to a non-tank process unit component or to a storage tank subject to the other 40 CFR part 63 subpart, the owner or operator must be in compliance with the recordkeeping and reporting requirements of this subpart EEEE. If complying with the recordkeeping and reporting requirements of the other subpart satisfies the recordkeeping and reporting requirements of this subpart, the owner or operator may elect to continue to comply with the recordkeeping and reporting requirements of the other subpart. In such instances, the owner or operator will be deemed to be in compliance with the recordkeeping and reporting requirements of this subpart. The owner or operator must identify the other subpart being complied with in the Notification of Compliance Status required by §63.2382(b).

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42911, July 28, 2006]

[↑ Back to Top](#)

§63.2398 What parts of the General Provisions apply to me?

Table 12 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

[↑ Back to Top](#)

§63.2402 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. Environmental Protection Agency (U.S. EPA) or a delegated authority such as your State, local, or eligible tribal agency. If the EPA Administrator has delegated authority to your State, local, or eligible tribal agency, then that agency, as well as the EPA, has the authority to implement and enforce this subpart. You should contact your EPA Regional Office (see list in §63.13) to find out if this subpart is delegated to your State, local, or eligible tribal agency.

(b) In delegating implementation and enforcement authority for this subpart to a State, local, or eligible tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not delegated to the State, local, or eligible tribal agency.

(1) Approval of alternatives to the nonopacity emission limitations, operating limits, and work practice standards in §63.2346(a) through (c) under §63.6(g).

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42911, July 28, 2006]

[↑ Back to Top](#)

§63.2406 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2, 40 CFR part 63, subparts H, PP, SS, TT, UU, and WW, and in this section. If the same term is defined in another subpart and in this section, it will have the meaning given in this section for purposes of this subpart.

Notwithstanding the introductory language in §63.921, the terms “container” and “safety device” shall have the meaning found in this subpart and not in §63.921.

Actual annual average temperature, for organic liquids, means the temperature determined using the following methods:

(1) For heated or cooled storage tanks, use the calculated annual average temperature of the stored organic liquid as determined from a design analysis of the storage tank.

(2) For ambient temperature storage tanks:

(i) Use the annual average of the local (nearest) normal daily mean temperatures reported by the National Climatic Data Center; or

(ii) Use any other method that the EPA approves.

Annual average true vapor pressure means the equilibrium partial pressure exerted by the total table 1 organic HAP in the stored or transferred organic liquid. For the purpose of determining if a liquid meets the definition of an organic liquid, the vapor pressure is determined using standard conditions of 77 degrees F and 29.92 inches of mercury. For the purpose of determining whether an organic liquid meets the applicability criteria in table 2, items 1 through 6, to this subpart, use

the actual annual average temperature as defined in this subpart. The vapor pressure value in either of these cases is determined:

- (1) In accordance with methods described in American Petroleum Institute Publication 2517, Evaporative Loss from External Floating-Roof Tanks (incorporated by reference, see §63.14);
- (2) Using standard reference texts;
- (3) By the American Society for Testing and Materials Method D2879-83, 96 (incorporated by reference, see §63.14); or
- (4) Using any other method that the EPA approves.

Bottoms receiver means a tank that collects distillation bottoms before the stream is sent for storage or for further processing downstream.

Cargo tank means a liquid-carrying tank permanently attached and forming an integral part of a motor vehicle or truck trailer. This term also refers to the entire cargo tank motor vehicle or trailer. For the purpose of this subpart, vacuum trucks used exclusively for maintenance or spill response are not considered cargo tanks.

Closed vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapors from an emission point to a control device. This system does not include the vapor collection system that is part of some transport vehicles or the loading arm or hose that is used for vapor return. For transfer racks, the closed vent system begins at, and includes, the first block valve on the downstream side of the loading arm or hose used to convey displaced vapors.

Combustion device means an individual unit of equipment, such as a flare, oxidizer, catalytic oxidizer, process heater, or boiler, used for the combustion of organic emissions.

Container means a portable unit in which a material can be stored, transported, treated, disposed of, or otherwise handled. Examples of containers include, but are not limited to, drums and portable cargo containers known as “portable tanks” or “totes.”

Control device means any combustion device, recovery device, recapture device, or any combination of these devices used to comply with this subpart. Such equipment or devices include, but are not limited to, absorbers, adsorbers, condensers, and combustion devices. Primary condensers, steam strippers, and fuel gas systems are not considered control devices.

Crude oil means any of the naturally occurring liquids commonly referred to as crude oil, regardless of specific physical properties. Only those crude oils downstream of the first point of custody transfer after the production field are considered crude oils in this subpart.

Custody transfer means the transfer of hydrocarbon liquids after processing and/or treatment in the producing operations, or from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

Design evaluation means a procedure for evaluating control devices that complies with the requirements in §63.985(b)(1)(i).

Deviation means any instance in which an affected source subject to this subpart, or portion thereof, 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 limitation (including any 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 limitation (including any operating limit) or work practice standard in this subpart during SSM.

Emission limitation means an emission limit, opacity limit, operating limit, or visible emission limit.

Equipment leak component means each pump, valve, and sampling connection system used in organic liquids service at an OLD operation. Valve types include control, globe, gate, plug, and ball. Relief and check valves are excluded.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals (4.0 pounds per square inch absolute (psia)) or greater which is used as a fuel for internal combustion engines. Aviation gasoline is included in this definition.

High throughput transfer rack means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) a total of 11.8 million liters per year or greater of organic liquids.

In organic liquids service means that an equipment leak component contains or contacts organic liquids having 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart.

Low throughput transfer rack means those transfer racks that transfer into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) less than 11.8 million liters per year of organic liquids.

On-site or *on site* means, with respect to records required to be maintained by this subpart or required by another subpart referenced by this subpart, that records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to,

storage at the affected source to which the records pertain, storage in central files elsewhere at the major source, or electronically available at the site.

Organic liquid means:

(1) Any non-crude oil liquid or liquid mixture that contains 5 percent by weight or greater of the organic HAP listed in Table 1 to this subpart, as determined using the procedures specified in §63.2354(c).

(2) Any crude oils downstream of the first point of custody transfer.

(3) Organic liquids for purposes of this subpart do not include the following liquids:

(i) Gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils;

(ii) Any fuel consumed or dispensed on the plant site directly to users (such as fuels for fleet refueling or for refueling marine vessels that support the operation of the plant);

(iii) Hazardous waste;

(iv) Wastewater;

(v) Ballast water: or

(vi) Any non-crude oil liquid with an annual average true vapor pressure less than 0.7 kilopascals (0.1 psia).

Organic liquids distribution (OLD) operation means the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed. Activities include, but are not limited to, storage, transfer, blending, compounding, and packaging.

Permitting authority means one of the following:

(1) The State Air Pollution Control Agency, local agency, or other agency authorized by the EPA Administrator to carry out a permit program under 40 CFR part 70; or

(2) The EPA Administrator, in the case of EPA-implemented permit programs under title V of the CAA (42 U.S.C. 7661) and 40 CFR part 71.

Plant site means all contiguous or adjoining surface property that is under common control, including surface properties that are separated only by a road or other public right-of-way. Common control includes surface properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and which are not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.

Responsible official means responsible official as defined in 40 CFR 70.2 and 40 CFR 71.2, as applicable.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device that functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event.

Shutdown means the cessation of operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), including equipment required or used to comply with this subpart, or the emptying and degassing of a storage tank. Shutdown as defined here includes, but is not limited to, events that result from periodic maintenance, replacement of equipment, or repair.

Startup means the setting in operation of an OLD affected source, or portion thereof (other than as part of normal operation of a batch-type operation), for any purpose. Startup also includes the placing in operation of any individual piece of equipment required or used to comply with this subpart including, but not limited to, control devices and monitors.

Storage tank means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, or reinforced plastic) that provide structural support and is designed to hold a bulk quantity of liquid. Storage tanks do not include:

- (1) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
- (2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (3) Bottoms receivers;
- (4) Surge control vessels;
- (5) Vessels storing wastewater; or
- (6) Reactor vessels associated with a manufacturing process unit.

Surge control vessel means feed drums, recycle drums, and intermediate vessels. Surge control vessels are used within chemical manufacturing processes when in-process storage, mixing, or management of flow rates or volumes is needed to assist in production of a product.

Tank car means a car designed to carry liquid freight by rail, and including a permanently attached tank.

Total actual annual facility-level organic liquid loading volume means the total facility-level actual volume of organic liquid loaded for transport within or out of the facility through transfer racks that are part of the affected source into transport vehicles (for existing affected sources) or into transport vehicles and containers (for new affected sources) based on a 3-year rolling average, calculated annually.

(1) For existing affected sources, each 3-year rolling average is based on actual facility-level loading volume during each calendar year (January 1 through December 31) in the 3-year period. For calendar year 2004 only (the first year of the initial 3-year rolling average), if an owner or operator of an affected source does not have actual loading volume data for the time period from January 1, 2004, through February 2, 2004 (the time period prior to the effective date of the OLD NESHAP), the owner or operator shall compute a facility-level loading volume for this time period as follows: At the end of the 2004 calendar year, the owner or operator shall calculate a daily average facility-level loading volume (based on the actual loading volume for February 3, 2004, through December 31, 2004) and use that daily average to estimate the facility-level loading volume for the period of time from January 1, 2004, through February 2, 2004. The owner or operator shall then sum the estimated facility-level loading volume from January 1, 2004, through February 2, 2004, and the actual facility-level loading volume from February 3, 2004, through December 31, 2004, to calculate the annual facility-level loading volume for calendar year 2004.

(2)(i) For new affected sources, the 3-year rolling average is calculated as an average of three 12-month periods. An owner or operator must select as the beginning calculation date with which to start the calculations as either the initial startup date of the new affected source or the first day of the calendar month following the month in which startup occurs. Once selected, the date with which the calculations begin cannot be changed.

(ii) The initial 3-year rolling average is based on the projected maximum facility-level annual loading volume for each of the 3 years following the selected beginning calculation date. The second 3-year rolling average is based on actual facility-level loading volume for the first year of operation plus a new projected maximum facility-level annual loading volume for second and third years following the selected beginning calculation date. The third 3-year rolling average is based on actual facility-level loading volume for the first 2 years of operation plus a new projected maximum annual facility-level loading volume for the third year following the beginning calculation date. Subsequent 3-year rolling averages are based on actual facility-level loading volume for each year in the 3-year rolling average.

Transfer rack means a single system used to load organic liquids into, or unload organic liquids out of, transport vehicles or containers. It includes all loading and unloading arms, pumps, meters, shutoff valves, relief valves, and other piping and equipment necessary for the transfer operation. Transfer equipment and operations that are physically separate (i.e., do not share common piping, valves, and other equipment) are considered to be separate transfer racks.

Transport vehicle means a cargo tank or tank car.

Vapor balancing system means:

- (1) A piping system that collects organic HAP vapors displaced from transport vehicles or containers during loading and routes the collected vapors to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header. For containers, the piping system must route the displaced vapors directly to the appropriate storage tank or to another storage tank connected to a common header in order to qualify as a vapor balancing system; or
- (2) A piping system that collects organic HAP vapors displaced from the loading of a storage tank and routes the collected vapors to the transport vehicle from which the storage tank is filled.

Vapor collection system means any equipment located at the source (i.e., at the OLD operation) that is not open to the atmosphere; that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for:

- (1) Containing and conveying vapors displaced during the loading of transport vehicles to a control device;
- (2) Containing and directly conveying vapors displaced during the loading of containers; or
- (3) Vapor balancing. This does not include any of the vapor collection equipment that is installed on the transport vehicle.

Vapor-tight transport vehicle means a transport vehicle that has been demonstrated to be vapor-tight. To be considered vapor-tight, a transport vehicle equipped with vapor collection equipment must undergo a pressure change of no more than 250 pascals (1 inch of water) within 5 minutes after it is pressurized to 4,500 pascals (18 inches of water). This capability must be demonstrated annually using the procedures specified in EPA Method 27 of 40 CFR part 60, appendix A. For all other transport vehicles, vapor tightness is demonstrated by performing the U.S. DOT pressure test procedures for tank cars and cargo tanks.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42911, July 28, 2006]

[!\[\]\(0b5e7e25e8775f7e7e80906ada4f0021_img.jpg\) Back to Top](#)

Table 1 to Subpart EEEE of Part 63—Organic Hazardous Air Pollutants

You must use the organic HAP information listed in the following table to determine which of the liquids handled at your facility meet the HAP content criteria in the definition of Organic Liquid in §63.2406.

Compound name	CAS No. ¹
2,4-D salts and esters	94-75-7
Acetaldehyde	75-07-0
Acetonitrile	75-05-8
Acetophenone	98-86-2
Acrolein	107-02-8
Acrylamide	79-06-1
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Allyl chloride	107-05-1
Aniline	62-53-3
Benzene	71-43-2
Biphenyl	92-52-4
Butadiene (1,3-)	106-99-0
Carbon tetrachloride	56-23-5
Chloroacetic acid	79-11-8
Chlorobenzene	108-90-7
2-Chloro-1,3-butadiene (Chloroprene)	126-99-8
Chloroform	67-66-3
m-Cresol	108-39-4
o-Cresol	95-48-7
p-Cresol	106-44-5
Cresols/cresylic acid	1319-77-3
Cumene	98-82-8
Dibenzofurans	132-64-9
Dibutylphthalate	84-74-2
Dichloroethane (1,2-) (Ethylene dichloride) (EDC)	107-06-2
Dichloropropene (1,3-)	542-75-6
Diethanolamine	111-42-2
Diethyl aniline (N,N-)	121-69-7
Diethylene glycol monobutyl ether	112-34-5
Diethylene glycol monomethyl ether	111-77-3
Diethyl sulfate	64-67-5

Dimethyl formamide	68-12-2
Dimethylhydrazine (1,1-)	57-14-7
Dioxane (1,4-) (1,4-Diethyleneoxide)	123-91-1
Epichlorohydrin (1-Chloro-2,3-epoxypropane)	106-89-8
Epoxybutane (1,2-)	106-88-7
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride (Chloroethane)	75-00-3
Ethylene dibromide (Dibromomethane)	106-93-4
Ethylene glycol	107-21-1
Ethylene glycol dimethyl ether	110-71-4
Ethylene glycol monomethyl ether	109-86-4
Ethylene glycol monomethyl ether acetate	110-49-6
Ethylene glycol monophenyl ether	122-99-6
Ethylene oxide	75-21-8
Ethylidene dichloride (1,1-Dichloroethane)	75-34-3
Formaldehyde	50-00-0
Hexachloroethane	67-72-1
Hexane	110-54-3
Hydroquinone	123-31-9
Isophorone	78-59-1
Maleic anhydride	108-31-6
Methanol	67-56-1
Methyl chloride (Chloromethane)	74-87-3
Methylene chloride (Dichloromethane)	75-09-2
Methylenedianiline (4,4'-)	101-77-9
Methylene diphenyl diisocyanate	101-68-8
Methyl hydrazine	60-34-4
Methyl isobutyl ketone (Hexone) (MIBK)	108-10-1
Methyl methacrylate	80-62-6
Methyl tert-butyl ether (MTBE)	1634-04-4
Naphthalene	91-20-3
Nitrobenzene	98-95-3
Phenol	108-9-52
Phthalic anhydride	85-44-9
Polycyclic organic matter	50-32-8

Propionaldehyde	123-38-6
Propylene dichloride (1,2-Dichloropropane)	78-87-5
Propylene oxide	75-56-9
Quinoline	91-22-5
Styrene	100-42-5
Styrene oxide	96-09-3
Tetrachloroethane (1,1,2,2-)	79-34-5
Tetrachloroethylene (Perchloroethylene)	127-18-4
Toluene	108-88-3
Toluene diisocyanate (2,4-)	584-84-9
o-Toluidine	95-53-4
Trichlorobenzene (1,2,4-)	120-82-1
Trichloroethane (1,1,1-) (Methyl chloroform)	71-55-6
Trichloroethane (1,1,2-) (Vinyl trichloride)	79-00-5
Trichloroethylene	79-01-6
Triethylamine	121-44-8
Trimethylpentane (2,2,4-)	540-84-1
Vinyl acetate	108-05-4
Vinyl chloride (Chloroethylene)	75-01-4
Vinylidene chloride (1,1-Dichloroethylene)	75-35-4
Xylene (m-)	108-38-3
Xylene (o-)	95-47-6
Xylene (p-)	106-42-3
Xylenes (isomers and mixtures)	1330-20-7

¹CAS numbers refer to the Chemical Abstracts Services registry number assigned to specific compounds, isomers, or mixtures of compounds.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42913, July 28, 2006]

[↑ Back to Top](#)

Table 2 to Subpart EEEE of Part 63—Emission Limits

As stated in §63.2346, you must comply with the emission limits for the organic liquids distribution emission sources as follows:

If you own or operate . . .	And if . . .	Then you must . . .
1. A storage tank at an	a. The stored organic	i. Reduce emissions of total organic

existing affected source with a capacity ≥ 18.9 cubic meters (5,000 gallons) and < 189.3 cubic meters (50,000 gallons).	liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid is ≥ 27.6 kilopascals (4.0 psia) and < 76.6 kilopascals (11.1 psia).	HAP (or, upon approval, TOC) by at least 95 weight-percent or, as an option, to an exhaust concentration less than or equal to 20 ppmv, on a dry basis corrected to 3 percent oxygen for combustion devices using supplemental combustion air, by venting emissions through a closed vent system to any combination of control devices meeting the applicable requirements of 40 CFR part 63, subpart SS; OR
		ii. Comply with the work practice standards specified in table 4 to this subpart, items 1.a, 1.b, or 1.c for tanks storing liquids described in that table.
	b. The stored organic liquid is crude oil.	i. See the requirement in item 1.a.i or 1.a.ii of this table.
2. A storage tank at an existing affected source with a capacity ≥ 189.3 cubic meters (50,000 gallons).	a. The stored organic liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid is < 76.6 kilopascals (11.1 psia).	i. See the requirement in item 1.a.i or 1.a.ii of this table.
	b. The stored organic liquid is crude oil.	i. See the requirement in item 1.a.i or 1.a.ii of this table.
3. A storage tank at a reconstructed or new affected source with a capacity ≥ 18.9 cubic meters (5,000 gallons) and < 37.9 cubic meters (10,000 gallons).	a. The stored organic liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid is ≥ 27.6 kilopascals (4.0 psia) and < 76.6 kilopascals (11.1 psia).	i. See the requirement in item 1.a.i or 1.a.ii of this table.
	b. The stored organic liquid is crude oil.	i. See the requirement in item 1.a.i or 1.a.ii of this table.
4. A storage tank at a reconstructed or new affected source with a capacity ≥ 37.9 cubic meters (10,000 gallons) and < 189.3 cubic meters	a. The stored organic liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in	i. See the requirement in item 1.a.i or 1.a.ii of this table.

(50,000 gallons).	the stored organic liquid is ≥ 0.7 kilopascals (0.1 psia) and < 76.6 kilopascals (11.1 psia).	
	b. The stored organic liquid is crude oil.	i. See the requirement in item 1.a.i or 1.a.ii of this table.
5. A storage tank at a reconstructed or new affected source with a capacity ≥ 189.3 cubic meters (50,000 gallons).	a. The stored organic liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid is < 76.6 kilopascals (11.1 psia).	i. See the requirement in item 1.a.i or 1.a.ii of this table.
	b. The stored organic liquid is crude oil.	i. See the requirement in item 1.a.i or 1.a.ii of this table.
6. A storage tank at an existing, reconstructed, or new affected source meeting the capacity criteria specified in table 2 of this subpart, items 1 through 5.	a. The stored organic liquid is not crude oil and if the annual average true vapor pressure of the total Table 1 organic HAP in the stored organic liquid is ≥ 76.6 kilopascals (11.1 psia).	i. Reduce emissions of total organic HAP (or, upon approval, TOC) by at least 95 weight-percent or, as an option, to an exhaust concentration less than or equal to 20 ppmv, on a dry basis corrected to 3 percent oxygen for combustion devices using supplemental combustion air, by venting emissions through a closed vent system to any combination of control devices meeting the applicable requirements of 40 CFR part 63, subpart SS; OR
		ii. Comply with the work practice standards specified in table 4 to this subpart, item 2.a, for tanks storing the liquids described in that table.
7. A transfer rack at an existing facility where the total actual annual facility-level organic liquid loading volume through transfer racks is equal to or greater than 800,000 gallons and less than 10 million gallons.	a. The total table 1 organic HAP content of the organic liquid being loaded through one or more of the transfer rack's arms is at least 98 percent by weight and is being loaded into a transport vehicle.	i. For all such loading arms at the rack, reduce emissions of total organic HAP (or, upon approval, TOC) from the loading of organic liquids either by venting the emissions that occur during loading through a closed vent system to any combination of control devices meeting the applicable requirements of 40 CFR part 63, subpart SS, achieving at least 98 weight-percent HAP reduction, OR, as

		an option, to an exhaust concentration less than or equal to 20 ppmv, on a dry basis corrected to 3 percent oxygen for combustion devices using supplemental combustion air; OR
		ii. During the loading of organic liquids, comply with the work practice standards specified in item 3 of table 4 to this subpart.
8. A transfer rack at an existing facility where the total actual annual facility-level organic liquid loading volume through transfer racks is ≥ 10 million gallons.	a. One or more of the transfer rack's arms is loading an organic liquid into a transport vehicle.	i. See the requirements in items 7.a.i and 7.a.ii of this table.
9. A transfer rack at a new facility where the total actual annual facility-level organic liquid loading volume through transfer racks is less than 800,000 gallons	a. The total Table 1 organic HAP content of the organic liquid being loaded through one or more of the transfer rack's arms is at least 25 percent by weight and is being loaded into a transport vehicle	i. See the requirements in items 7.a.i and 7.a.ii of this table.
	b. One or more of the transfer rack's arms is filling a container with a capacity equal to or greater than 55 gallons	i. For all such loading arms at the rack during the loading of organic liquids, comply with the provisions of §§63.924 through 63.927 of 40 CFR part 63, Subpart PP—National Emission Standards for Containers, Container Level 3 controls; OR ii. During the loading of organic liquids, comply with the work practice standards specified in item 3.a of Table 4 to this subpart.
10. A transfer rack at a new facility where the total actual annual facility-level organic liquid loading volume through transfer racks is equal to or greater than 800,000 gallons.	a. One or more of the transfer rack's arms is loading an organic liquid into a transport vehicle.	i. See the requirements in items 7.a.i and 7.a.ii of this table.
	b. One or more of the transfer rack's arms is	i. For all such loading arms at the rack during the loading of organic liquids,

	filling a container with a capacity equal to or greater than 55 gallons.	comply with the provisions of §§63.924 through 63.927 of 40 CFR part 63, Subpart PP—National Emission Standards for Containers, Container Level 3 controls; OR
		ii. During the loading of organic liquids, comply with the work practice standards specified in item 3.a of table 4 to this subpart.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42913, July 28, 2006; 73 FR 21830, Apr. 23, 2008]

[↑ Back to Top](#)

Table 3 to Subpart EEEE of Part 63—Operating Limits—High Throughput Transfer Racks

As stated in §63.2346(e), you must comply with the operating limits for existing, reconstructed, or new affected sources as follows:

For each existing, each reconstructed, and each new affected source using . . .	You must . . .
1. A thermal oxidizer to comply with an emission limit in table 2 to this subpart	Maintain the daily average fire box or combustion zone temperature greater than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.
2. A catalytic oxidizer to comply with an emission limit in table 2 to this subpart	a. Replace the existing catalyst bed before the age of the bed exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	b. Maintain the daily average temperature at the inlet of the catalyst bed greater than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	c. Maintain the daily average temperature difference across the catalyst bed greater than or equal to the minimum temperature difference established during the design evaluation or performance test that demonstrated compliance with the emission limit.
3. An absorber to comply with an emission limit in table 2 to	a. Maintain the daily average concentration level of organic compounds in the absorber exhaust less than or equal to the

this subpart	reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR
	b. Maintain the daily average scrubbing liquid temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	Maintain the difference between the specific gravities of the saturated and fresh scrubbing fluids greater than or equal to the difference established during the design evaluation or performance test that demonstrated compliance with the emission limit.
4. A condenser to comply with an emission limit in table 2 to this subpart	a. Maintain the daily average concentration level of organic compounds at the condenser exit less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR
	b. Maintain the daily average condenser exit temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.
5. An adsorption system with adsorbent regeneration to comply with an emission limit in table 2 to this subpart	a. Maintain the daily average concentration level of organic compounds in the adsorber exhaust less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR
	b. Maintain the total regeneration stream mass flow during the adsorption bed regeneration cycle greater than or equal to the reference stream mass flow established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	Before the adsorption cycle commences, achieve and maintain the temperature of the adsorption bed after regeneration less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	Achieve a pressure reduction during each adsorption bed regeneration cycle greater than or equal to the pressure reduction established during the design evaluation or performance test that demonstrated compliance with the emission limit.
6. An adsorption system without adsorbent regeneration to comply with an emission limit in table 2 to this subpart	a. Maintain the daily average concentration level of organic compounds in the adsorber exhaust less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the

	emission limit; OR
	b. Replace the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation or performance test before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND
	Maintain the temperature of the adsorption bed less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.
7. A flare to comply with an emission limit in table 2 to this subpart	a. Comply with the equipment and operating requirements in §63.987(a); AND b. Conduct an initial flare compliance assessment in accordance with §63.987(b); AND
	c. Install and operate monitoring equipment as specified in §63.987(c).
8. Another type of control device to comply with an emission limit in table 2 to this subpart	Submit a monitoring plan as specified in §§63.995(c) and 63.2366(b), and monitor the control device in accordance with that plan.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42914, July 28, 2006]

[↑ Back to Top](#)

Table 4 to Subpart EEEE of Part 63—Work Practice Standards

As stated in §63.2346, you may elect to comply with one of the work practice standards for existing, reconstructed, or new affected sources in the following table. If you elect to do so, . . .

For each . . .	You must . . .
1. Storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and organic HAP vapor pressure criteria specified in table 2 to this subpart, items 1 through 5	a. Comply with the requirements of 40 CFR part 63, subpart WW (control level 2), if you elect to meet 40 CFR part 63, subpart WW (control level 2) requirements as an alternative to the emission limit in table 2 to this subpart, items 1 through 5; OR
	b. Comply with the requirements of §63.984 for routing emissions to a fuel gas system or back to a process; OR
	c. Comply with the requirements of §63.2346(a)(4) for

	vapor balancing emissions to the transport vehicle from which the storage tank is filled.
2. Storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and organic HAP vapor pressure criteria specified in table 2 to this subpart, item 6	a. Comply with the requirements of §63.984 for routing emissions to a fuel gas system or back to a process; OR b. Comply with the requirements of §63.2346(a)(4) for vapor balancing emissions to the transport vehicle from which the storage tank is filled.
3. Transfer rack subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source	a. If the option of a vapor balancing system is selected, install and, during the loading of organic liquids, operate a system that meets the requirements in table 7 to this subpart, item 3.b.i and item 3.b.ii, as applicable; OR
	b. Comply with the requirements of §63.984 during the loading of organic liquids, for routing emissions to a fuel gas system or back to a process.
4. Pump, valve, and sampling connection that operates in organic liquids service at least 300 hours per year at an existing, reconstructed, or new affected source	Comply with the requirements for pumps, valves, and sampling connections in 40 CFR part 63, subpart TT (control level 1), subpart UU (control level 2), or subpart H.
5. Transport vehicles equipped with vapor collection equipment that are loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10	Follow the steps in 40 CFR 60.502(e) to ensure that organic liquids are loaded only into vapor-tight transport vehicles, and comply with the provisions in 40 CFR 60.502(f), (g), (h), and (i), except substitute the term transport vehicle at each occurrence of tank truck or gasoline tank truck in those paragraphs.
6. Transport vehicles equipped without vapor collection equipment that are loaded at transfer racks that are subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10	Ensure that organic liquids are loaded only into transport vehicles that have a current certification in accordance with the U.S. DOT pressure test requirements in 49 CFR 180 (cargo tanks) or 49 CFR 173.31 (tank cars).

[71 FR 42915, July 28, 2006]

[↑ Back to Top](#)

Table 5 to Subpart EEEE of Part 63—Requirements for Performance Tests and Design Evaluations

As stated in §§63.2354(a) and 63.2362, you must comply with the requirements for performance tests and design evaluations for existing, reconstructed, or new affected sources as follows:

For . . .	You must conduct . . .	According to . . .	Using . . .	To determine . . .	According to the following requirements . . .
1. Each existing, each reconstructed, and each new affected source using a nonflare control device to comply with an emission limit in Table 2 to this subpart, items 1 through 10	a. A performance test to determine the organic HAP (or, upon approval, TOC) control efficiency of each nonflare control device, OR the exhaust concentration of each combustion device; OR	i. §63.985(b)(1)(ii), §63.988(b), §63.990(b), or §63.995(b)	(1) EPA Method 1 or 1A in appendix A-1 of 40 CFR part 60, as appropriate	(A) Sampling port locations and the required number of traverse points	(i) Sampling sites must be located at the inlet and outlet of each control device if complying with the control efficiency requirement or at the outlet of the control device if complying with the exhaust concentration requirement; AND (ii) the outlet sampling site must be located at each control device prior to any releases to the atmosphere.
			(2) EPA Method 2, 2A, 2C, 2D, or 2F in appendix A-1 of 40 CFR part 60, or EPA Method 2G in appendix A-2 of 40 CFR part 60, as appropriate	(A) Stack gas velocity and volumetric flow rate	See the requirements in items 1.a.i.(1)(A)(i) and (ii) of this table.
			(3) EPA Method 3 or	(A) Concentration	See the requirements in

			3B in appendix A-2 of 40 CFR part 60, as appropriate	of CO ₂ and O ₂ and dry molecular weight of the stack gas	items 1.a.i.(1)(A)(i) and (ii) of this table.
			(4) EPA Method 4 in appendix A-3 of 40 CFR part 60	(A) Moisture content of the stack gas	See the requirements in items 1.a.i.(1)(A)(i) and (ii) of this table.
			(5) EPA Method 18 in appendix A-6 of 40 CFR part 60, or EPA Method 25 or 25A in appendix A-7 of 40 CFR part 60, as appropriate, or EPA Method 316 in appendix A of 40 CFR part 63 for measuring form-aldehyde	(A) Total organic HAP (or, upon approval, TOC), or formaldehyde emissions	(i) The organic HAP used for the calibration gas for EPA Method 25A in appendix A-7 of 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of emissions; AND (ii) During the performance test, you must establish the operating parameter limits within which total organic HAP (or, upon approval, TOC) emissions are reduced by the required weight-percent or, as an option for nonflare combustion devices, to 20 ppmv exhaust concentration.

	b. A design evaluation (for nonflare control devices) to determine the organic HAP (or, upon approval, TOC) control efficiency of each nonflare control device, or the exhaust concentration of each combustion control device	§63.985(b)(1)(i)			During a design evaluation, you must establish the operating parameter limits within which total organic HAP, (or, upon approval, TOC) emissions are reduced by at least 95 weight-percent for storage tanks or 98 weight-percent for transfer racks, or, as an option for nonflare combustion devices, to 20 ppmv exhaust concentration.
2. Each transport vehicle that you own that is equipped with vapor collection equipment and is loaded with organic liquids at a transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source	A performance test to determine the vapor tightness of the tank and then repair as needed until it passes the test.		EPA Method 27 in appendix A of 40 CFR part 60	Vapor tightness	The pressure change in the tank must be no more than 250 pascals (1 inch of water) in 5 minutes after it is pressurized to 4,500 pascals (18 inches of water).

[71 FR 42916, July 28, 2006, as amended at 73 FR 21831, Apr. 23, 2008]

[↑ Back to Top](#)

Table 6 to Subpart EEEE of Part 63—Initial Compliance With Emission Limits

As stated in §§63.2370(a) and 63.2382(b), you must show initial compliance with the emission limits for existing, reconstructed, or new affected sources as follows:

For each . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and liquid organic HAP vapor pressure criteria specified in Table 2 to this subpart, items 1 through 6	Reduce total organic HAP (or, upon approval, TOC) emissions by at least 95 weight-percent, or as an option for nonflare combustion devices to an exhaust concentration of ≤ 20 ppmv	Total organic HAP (or, upon approval, TOC) emissions, based on the results of the performance testing or design evaluation specified in Table 5 to this subpart, item 1.a or 1.b, respectively, are reduced by at least 95 weight-percent or as an option for nonflare combustion devices to an exhaust concentration ≤ 20 ppmv.
2. Transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source	Reduce total organic HAP (or, upon approval, TOC) emissions from the loading of organic liquids by at least 98 weight-percent, or as an option for nonflare combustion devices to an exhaust concentration of ≤ 20 ppmv	Total organic HAP (or, upon approval, TOC) emissions from the loading of organic liquids, based on the results of the performance testing or design evaluation specified in table 5 to this subpart, item 1.a or 1.b, respectively, are reduced by at least 98 weight-percent or as an option for nonflare combustion devices to an exhaust concentration of ≤ 20 ppmv.

[71 FR 42918, July 28, 2006, as amended at 73 FR 21832, Apr. 23, 2008]

[↑ Back to Top](#)

Table 7 to Subpart EEEE of Part 63—Initial Compliance With Work Practice Standards

For each . . .	If you . . .	You have demonstrated initial compliance
----------------	--------------	--

		if . . .
1. Storage tank at an existing affected source meeting either set of tank capacity and liquid organic HAP vapor pressure criteria specified in Table 2 to this subpart, items 1 or 2	a. Install a floating roof or equivalent control that meets the requirements in Table 4 to this subpart, item 1.a	i. After emptying and degassing, you visually inspect each internal floating roof before the refilling of the storage tank and perform seal gap inspections of the primary and secondary rim seals of each external floating roof within 90 days after the refilling of the storage tank.
	b. Route emissions to a fuel gas system or back to a process	i. You meet the requirements in §63.984(b) and submit the statement of connection required by §63.984(c).
	c. Install and, during the filling of the storage tank with organic liquids, operate a vapor balancing system	i. You meet the requirements in §63.2346(a)(4).
2. Storage tank at a reconstructed or new affected source meeting any set of tank capacity and liquid organic HAP vapor pressure criteria specified in Table 2 to this subpart, items 3 through 5	a. Install a floating roof or equivalent control that meets the requirements in Table 4 to this subpart, item 1.a	i. You visually inspect each internal floating roof before the initial filling of the storage tank, and perform seal gap inspections of the primary and secondary rim seals of each external floating roof within 90 days after the initial filling of the storage tank.
	b. Route emissions to a fuel gas system or back to a process	i. See item 1.b.i of this table.
	c. Install and, during the filling of the storage tank with organic liquids, operate a vapor balancing system	i. See item 1.c.i of this table.
3. Transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source	a. Load organic liquids only into transport vehicles having current vapor tightness certification as described in table 4 to this subpart, item 5 and item 6	i. You comply with the provisions specified in table 4 to this subpart, item 5 or item 6, as applicable.
	b. Install and, during the loading of organic liquids, operate a vapor balancing system	i. You design and operate the vapor balancing system to route organic HAP vapors displaced from loading of organic liquids into transport vehicles to the

		storage tank from which the liquid being loaded originated or to another storage tank connected to a common header. ii. You design and operate the vapor balancing system to route organic HAP vapors displaced from loading of organic liquids into containers directly (e.g., no intervening tank or containment area such as a room) to the storage tank from which the liquid being loaded originated or to another storage tank connected to a common header.
	c. Route emissions to a fuel gas system or back to a process	i. See item 1.b.i of this table.
4. Equipment leak component, as defined in §63.2406, that operates in organic liquids service ≥ 300 hours per year at an existing, reconstructed, or new affected source	a. Carry out a leak detection and repair program or equivalent control according to one of the subparts listed in table 4 to this subpart, item 4.a	i. You specify which one of the control programs listed in table 4 to this subpart you have selected, OR ii. Provide written specifications for your equivalent control approach.

[71 FR 42918, July 28, 2006, as amended at 73 FR 21833, Apr. 23, 2008]

[↑ Back to Top](#)

Table 8 to Subpart EEEE of Part 63—Continuous Compliance With Emission Limits

As stated in §§63.2378(a) and (b) and 63.2390(b), you must show continuous compliance with the emission limits for existing, reconstructed, or new affected sources according to the following table:

For each . . .	For the following emission limit . . .	You must demonstrate continuous compliance by . . .
1. Storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and liquid organic HAP vapor pressure criteria specified in table 2 to this subpart, items 1 through	a. Reduce total organic HAP (or, upon approval, TOC) emissions from the closed vent system and control device by 95 weight-percent or greater, or as an option to 20 ppmv or less of total organic HAP (or, upon approval, TOC) in the	i. Performing CMS monitoring and collecting data according to §§63.2366, 63.2374, and 63.2378; AND ii. Maintaining the operating limits established during the

6	exhaust of combustion devices	design evaluation or performance test that demonstrated compliance with the emission limit.
2. Transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source	a. Reduce total organic HAP (or, upon approval, TOC) emissions during the loading of organic liquids from the closed vent system and control device by 98 weight-percent or greater, or as an option to 20 ppmv or less of total organic HAP (or, upon approval, TOC) in the exhaust of combustion devices	i. Performing CMS monitoring and collecting data according to §§63.2366, 63.2374, and 63.2378 during the loading of organic liquids; AND ii. Maintaining the operating limits established during the design evaluation or performance test that demonstrated compliance with the emission limit during the loading of organic liquids.

[71 FR 42919, July 28, 2006]

[↑ Back to Top](#)

Table 9 to Subpart EEEE of Part 63—Continuous Compliance With Operating Limits—High Throughput Transfer Racks

As stated in §§63.2378(a) and (b) and 63.2390(b), you must show continuous compliance with the operating limits for existing, reconstructed, or new affected sources according to the following table:

For each existing, reconstructed, and each new affected source using . . .	For the following operating limit . . .	You must demonstrate continuous compliance by . . .
1. A thermal oxidizer to comply with an emission limit in table 2 to this subpart.	a. Maintain the daily average fire box or combustion zone, as applicable, temperature greater than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.	i. Continuously monitoring and recording fire box or combustion zone, as applicable, temperature every 15 minutes and maintaining the daily average fire box temperature greater than or equal to the reference temperature established during the design evaluation or performance test

		that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
2. A catalytic oxidizer to comply with an emission limit in table 2 to this subpart.	a. Replace the existing catalyst bed before the age of the bed exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND	i. Replacing the existing catalyst bed before the age of the bed exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
	b. Maintain the daily average temperature at the inlet of the catalyst bed greater than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND	i. Continuously monitoring and recording the temperature at the inlet of the catalyst bed at least every 15 minutes and maintaining the daily average temperature at the inlet of the catalyst bed greater than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
	c. Maintain the daily average temperature difference across the catalyst bed greater than or equal to the minimum temperature difference established during the design evaluation or performance test that demonstrated compliance with the emission limit.	i. Continuously monitoring and recording the temperature at the outlet of the catalyst bed every 15 minutes and maintaining the daily average temperature difference across the catalyst bed greater than or equal to the minimum temperature difference established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
3. An absorber to comply with an emission limit in table 2 to this subpart.	a. Maintain the daily average concentration level of organic compounds in the absorber exhaust less than or equal to the reference concentration established during the design evaluation or	i. Continuously monitoring the organic concentration in the absorber exhaust and maintaining the daily average concentration less than or equal to the reference concentration established during the design

	performance test that demonstrated compliance with the emission limit; OR	evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
	b. Maintain the daily average scrubbing liquid temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND Maintain the difference between the specific gravities of the saturated and fresh scrubbing fluids greater than or equal to the difference established during the design evaluation or performance test that demonstrated compliance with the emission limit.	i. Continuously monitoring the scrubbing liquid temperature and maintaining the daily average temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Maintaining the difference between the specific gravities greater than or equal to the difference established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND iii. Keeping the applicable records required in §63.998.
4. A condenser to comply with an emission limit in table 2 to this subpart.	a. Maintain the daily average concentration level of organic compounds at the exit of the condenser less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR	i. Continuously monitoring the organic concentration at the condenser exit and maintaining the daily average concentration less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
	b. Maintain the daily average condenser exit temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.	i. Continuously monitoring and recording the temperature at the exit of the condenser at least every 15 minutes and maintaining the daily average temperature less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records

		required in §63.998.
5. An adsorption system with adsorbent regeneration to comply with an emission limit in table 2 to this subpart.	a. Maintain the daily average concentration level of organic compounds in the adsorber exhaust less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR	i. Continuously monitoring the daily average organic concentration in the adsorber exhaust and maintaining the concentration less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Keeping the applicable records required in §63.998.
	b. Maintain the total regeneration stream mass flow during the adsorption bed regeneration cycle greater than or equal to the reference stream mass flow established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND Before the adsorption cycle commences, achieve and maintain the temperature of the adsorption bed after regeneration less than or equal to the reference temperature established during the design evaluation or performance test; AND Achieve greater than or equal to the pressure reduction during the adsorption bed regeneration cycle established during the design evaluation or performance test that demonstrated compliance with the emission limit.	i. Maintaining the total regeneration stream mass flow during the adsorption bed regeneration cycle greater than or equal to the reference stream mass flow established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND ii. Maintaining the temperature of the adsorption bed after regeneration less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND iii. Achieving greater than or equal to the pressure reduction during the regeneration cycle established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND iv. Keeping the applicable records required in §63.998.
6. An adsorption system without adsorbent regeneration to comply with an emission limit in table 2 to this subpart.	a. Maintain the daily average concentration level of organic compounds in the adsorber exhaust less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; OR	i. Continuously monitoring the organic concentration in the adsorber exhaust and maintaining the concentration less than or equal to the reference concentration established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND

		ii. Keeping the applicable records required in §63.998.
	<p>b. Replace the existing adsorbent in each segment of the bed before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND</p> <p>Maintain the temperature of the adsorption bed less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit.</p>	<p>i. Replacing the existing adsorbent in each segment of the bed with an adsorbent that meets the replacement specifications established during the design evaluation or performance test before the age of the adsorbent exceeds the maximum allowable age established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND</p> <p>ii. Maintaining the temperature of the adsorption bed less than or equal to the reference temperature established during the design evaluation or performance test that demonstrated compliance with the emission limit; AND</p> <p>iii. Keeping the applicable records required in §63.998.</p>
7. A flare to comply with an emission limit in table 2 to this subpart.	a. Maintain a pilot flame in the flare at all times that vapors may be vented to the flare (§63.11(b)(5)); AND	<p>i. Continuously operating a device that detects the presence of the pilot flame; AND</p> <p>ii. Keeping the applicable records required in §63.998.</p>
	b. Maintain a flare flame at all times that vapors are being vented to the flare (§63.11(b)(5)); AND	<p>i. Maintaining a flare flame at all times that vapors are being vented to the flare; AND</p> <p>ii. Keeping the applicable records required in §63.998.</p>
	c. Operate the flare with no visible emissions, except for up to 5 minutes in any 2 consecutive hours (§63.11(b)(4)); AND EITHER	<p>i. Operating the flare with no visible emissions exceeding the amount allowed; AND</p> <p>ii. Keeping the applicable records required in §63.998.</p>
	d.1. Operate the flare with an exit velocity that is within the applicable limits in §63.11(b)(7) and (8) and with a net heating value of the gas being combusted greater than the applicable minimum value in §63.11(b)(6)(ii); OR	<p>i. Operating the flare within the applicable exit velocity limits; AND</p> <p>ii. Operating the flare with the gas heating value greater than the applicable minimum value; AND</p> <p>iii. Keeping the applicable records required in §63.998.</p>

	d.2. Adhere to the requirements in §63.11(b)(6)(i).	i. Operating the flare within the applicable limits in 63.11(b)(6)(i); AND ii. Keeping the applicable records required in §63.998.
8. Another type of control device to comply with an emission limit in table 2 to this subpart.	Submit a monitoring plan as specified in §§63.995(c) and 63.2366(c), and monitor the control device in accordance with that plan.	Submitting a monitoring plan and monitoring the control device according to that plan.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42919, July 28, 2006]

[↑ Back to Top](#)

Table 10 to Subpart EEEE of Part 63—Continuous Compliance With Work Practice Standards

As stated in §§63.2378(a) and (b) and 63.2386(c)(6), you must show continuous compliance with the work practice standards for existing, reconstructed, or new affected sources according to the following table:

For each . . .	For the following standard . . .	You must demonstrate continuous compliance by . . .
1. Internal floating roof (IFR) storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity, and vapor pressure criteria specified in table 2 to this subpart, items 1 through 5.	a. Install a floating roof designed and operated according to the applicable specifications in §63.1063(a) and (b).	i. Visually inspecting the floating roof deck, deck fittings, and rim seals of each IFR once per year (§63.1063(d)(2)); AND ii. Visually inspecting the floating roof deck, deck fittings, and rim seals of each IFR either each time the storage tank is completely emptied and degassed or every 10 years, whichever occurs first (§63.1063(c)(1), (d)(1), and (e)); AND iii. Keeping the tank records required in §63.1065.
2. External floating roof (EFR) storage tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and vapor pressure criteria specified in table 2 to this subpart, items 1 through 5.	a. Install a floating roof designed and operated according to the applicable specifications in §63.1063(a) and (b).	i. Visually inspecting the floating roof deck, deck fittings, and rim seals of each EFR either each time the storage tank is completely emptied and degassed or every 10 years, whichever occurs first (§63.1063(c)(2), (d), and (e)); AND ii. Performing seal gap measurements on the secondary seal of each EFR at least

		once every year, and on the primary seal of each EFR at least every 5 years (§63.1063(c)(2), (d), and (e)); AND iii. Keeping the tank records required in §63.1065.
3. IFR or EFR tank at an existing, reconstructed, or new affected source meeting any set of tank capacity and vapor pressure criteria specified in table 2 to this subpart, items 1 through 5.	a. Repair the conditions causing storage tank inspection failures (§63.1063(e)).	i. Repairing conditions causing inspection failures: before refilling the storage tank with organic liquid, or within 45 days (or up to 105 days with extensions) for a tank containing organic liquid; AND ii. Keeping the tank records required in §63.1065(b).
4. Transfer rack that is subject to control based on the criteria specified in table 2 to this subpart, items 7 through 10, at an existing, reconstructed, or new affected source.	a. Ensure that organic liquids are loaded into transport vehicles in accordance with the requirements in table 4 to this subpart, items 5 or 6, as applicable.	i. Ensuring that organic liquids are loaded into transport vehicles in accordance with the requirements in table 4 to this subpart, items 5 or 6, as applicable.
	b. Install and, during the loading of organic liquids, operate a vapor balancing system.	i. Monitoring each potential source of vapor leakage in the system quarterly during the loading of a transport vehicle or the filling of a container using the methods and procedures described in the rule requirements selected for the work practice standard for equipment leak components as specified in table 4 to this subpart, item 4. An instrument reading of 500 ppmv defines a leak. Repair of leaks is performed according to the repair requirements specified in your selected equipment leak standards.
	c. Route emissions to a fuel gas system or back to a process.	i. Continuing to meet the requirements specified in §63.984(b).
5. Equipment leak component, as defined in §63.2406, that operates in organic liquids service at least 300 hours per year.	a. Comply with the requirements of 40 CFR part 63, subpart TT, UU, or H.	i. Carrying out a leak detection and repair program in accordance with the subpart selected from the list in item 5.a of this table.
6. Storage tank at an existing, reconstructed, or new affected source meeting	a. Route emissions to a fuel gas system or back to the process.	i. Continuing to meet the requirements specified in §63.984(b).

any of the tank capacity and vapor pressure criteria specified in table 2 to this subpart, items 1 through 6.		
	b. Install and, during the filling of the storage tank with organic liquids, operate a vapor balancing system.	i. Except for pressure relief devices, monitoring each potential source of vapor leakage in the system, including, but not limited to pumps, valves, and sampling connections, quarterly during the loading of a storage tank using the methods and procedures described in the rule requirements selected for the work practice standard for equipment leak components as specified in Table 4 to this subpart, item 4. An instrument reading of 500 ppmv defines a leak. Repair of leaks is performed according to the repair requirements specified in your selected equipment leak standards. For pressure relief devices, comply with §63.2346(a)(4)(v). If no loading of a storage tank occurs during a quarter, then monitoring of the vapor balancing system is not required.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 42922, July 28, 2006; 73 FR 40982, July 17, 2008]

[↑ Back to Top](#)

Table 11 to Subpart EEEE of Part 63—Requirements for Reports

As stated in §63.2386(a), (b), and (f), you must submit compliance reports and startup, shutdown, and malfunction reports according to the following table:

You must submit a(n) . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report or Periodic Report	a. The information specified in §63.2386(c), (d), (e). If you had a SSM during the reporting period and you took actions consistent with your SSM plan, the report must also include the information	Semiannually, and it must be postmarked by January 31 or July 31, in accordance with §63.2386(b).

	in §63.10(d)(5)(i); AND	
	b. The information required by 40 CFR part 63, subpart TT, UU, or H, as applicable, for pumps, valves, and sampling connections; AND	See the submission requirement in item 1.a of this table.
	c. The information required by §63.999(c); AND	See the submission requirement in item 1.a of this table.
	d. The information specified in §63.1066(b) including: Notification of inspection, inspection results, requests for alternate devices, and requests for extensions, as applicable.	See the submission requirement in item 1.a. of this table.
2. Immediate SSM report if you had a SSM that resulted in an applicable emission standard in the relevant standard being exceeded, and you took an action that was not consistent with your SSM plan	a. The information required in §63.10(d)(5)(ii)	i. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority (§63.10(d)(5)(ii)).

[71 FR 42923, July 28, 2006]

[↑ Back to Top](#)

Table 12 to Subpart EEEE of Part 63—Applicability of General Provisions to Subpart EEEE

As stated in §§63.2382 and 63.2398, you must comply with the applicable General Provisions requirements as follows:

Citation	Subject	Brief description	Applies to subpart EEEE
§63.1	Applicability	Initial applicability determination; Applicability after standard established; Permit requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63	Yes.

		standards	
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities and Circumvention	Prohibited activities; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; Applications; Approvals	Yes.
§63.6(a)	Compliance with Standards/O&M Applicability	GP apply unless compliance extension; GP apply to area sources that become major	Yes.
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for section 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved].		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Comply according to date in this subpart, which must be no later than 3 years after effective date; for section 112(f) standards, comply within 90 days of effective date unless compliance extension	Yes.
§63.6(c)(3)-(4)	[Reserved].		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That	Area sources that become major must comply with	Yes.

	Become Major	major source standards by date indicated in this subpart or by equivalent time period (<i>e.g.</i> , 3 years)	
§63.6(d)	[Reserved].		
§63.6(e)(1)	Operation & Maintenance	Operate to minimize emissions at all times; correct malfunctions as soon as practicable; and operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(2)	[Reserved].		
§63.6(e)(3)	SSM Plan	Requirement for SSM plan; content of SSM plan; actions during SSM	Yes; however, (1) the 2-day reporting requirement in paragraph §63.6(e)(3)(iv) does not apply and (2) §63.6(e)(3) does not apply to emissions sources not requiring control.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)-(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection	Yes.
§63.6(g)(1)-(3)	Alternative Standard	Procedures for getting an alternative standard	Yes.
§63.6(h)	Opacity/Visible Emission Standards	Requirements for compliance with opacity and visible emission standards	No; except as it applies to flares for which Method 22 observations are required as part of a flare compliance assessment.
§63.6(i)(1)-(14)	Compliance Extension	Procedures and criteria for	Yes.

		Administrator to grant compliance extension	
§63.6(j)	Presidential Compliance Exemption	President may exempt any source from requirement to comply with this subpart	Yes.
§63.7(a)(2)	Performance Test Dates	Dates for conducting initial performance testing; must conduct 180 days after compliance date	Yes.
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Rescheduling	If you have to reschedule performance test, must notify Administrator of rescheduled date as soon as practicable and without delay	Yes.
§63.7(c)	Quality Assurance (QA)/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with; test plan approval procedures; performance audit requirements; internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	Performance tests must be conducted under representative conditions; cannot conduct performance tests during SSM	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to this subpart and EPA test methods unless Administrator approves alternative	Yes.

§63.7(e)(3)	Test Run Duration	Must have three test runs of at least 1 hour each; compliance is based on arithmetic mean of three runs; conditions when data from an additional test run can be used	Yes; however, for transfer racks per §§63.987(b)(3)(i)(A)-(B) and 63.997(e)(1)(v)(A)-(B) provide exceptions to the requirement for test runs to be at least 1 hour each.
§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an intermediate or major change, or alternative to a test method	Yes.
§63.7(g)	Performance Test Data Analysis	Must include raw data in performance test report; must submit performance test data 60 days after end of test with the Notification of Compliance Status; keep data for 5 years	Yes; however, performance test data is to be submitted with the Notification of Compliance Status according to the schedule specified in §63.9(h)(1)-(6) below.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of 40 CFR part 60 apply	Yes.
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring of Flares	Monitoring requirements for flares in §63.11	Yes; however, monitoring requirements in §63.987(c) also apply.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b)(2)-(3)	Multiple Effluents and	Specific requirements for	Yes.

	Multiple Monitoring Systems	installing monitoring systems; must install on each affected source or after combined with another affected source before it is released to the atmosphere provided the monitoring is sufficient to demonstrate compliance with the standard; if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.
§63.8(c)(1)(i)-(iii)	Routine and Predictable SSM	Keep parts for routine repairs readily available; reporting requirements for SSM when action is described in SSM plan.	Yes.
§63.8(c)(2)-(3)	Monitoring System Installation	Must install to get representative emission or parameter measurements; must verify operational status before or at performance test	Yes.
§63.8(c)(4)	CMS Requirements	CMS must be operating except during breakdown, out-of control, repair, maintenance, and high-level calibration drifts; COMS must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period; CEMS must have a minimum of one cycle of	Yes; however, COMS are not applicable.

		operation for each successive 15-minute period	
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	No.
§63.8(c)(6)-(8)	CMS Requirements	Zero and high level calibration check requirements. Out-of-control periods	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(d)	CMS Quality Control	Requirements for CMS quality control, including calibration, etc.; must keep quality control plan on record for 5 years; keep old versions for 5 years after revisions	Yes, but only applies for CEMS. 40 CFR part 63, subpart SS provides requirements for CPMS.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	Yes, but only applies for CEMS.
§63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes, but 40 CFR part 63, subpart SS also provides procedures for approval of CPMS.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	Yes.
§63.8(g)	Data Reduction	COMS 6-minute averages calculated over at least 36 evenly spaced data points; CEMS 1 hour averages computed over at least 4 equally spaced data points; data that cannot be used in average	Yes; however, COMS are not applicable.
§63.9(a)	Notification Requirements	Applicability and State delegation	Yes.
§63.9(b)(1)-(2), (4)-(5)	Initial Notifications	Submit notification within 120 days after effective date; notification of intent to construct/reconstruct, notification of	Yes.

		commencement of construction/reconstruction , notification of startup; contents of each	
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed best available control technology or lowest achievable emission rate (BACT/LAER)	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Sources	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using CMS	Notification of performance evaluation; notification about use of COMS data; notification that exceeded criterion for relative accuracy alternative	Yes; however, there are no opacity standards.
§63.9(h)(1)-(6)	Notification of Compliance Status	Contents due 60 days after end of performance test or other compliance demonstration, except for opacity/visible emissions, which are due 30 days after; when to submit to Federal vs. State authority	Yes; however, (1) there are no opacity standards and (2) all initial Notification of Compliance Status, including all performance test data, are to be submitted at the same time, either within 240 days after the compliance date or within 60 days after the last performance test demonstrating compliance has been completed,

			whichever occurs first.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	No. These changes will be reported in the first and subsequent compliance reports.
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; when to submit to Federal vs. State authority; procedures for owners of more than one source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	General requirements; keep all records readily available; keep for 5 years	Yes.
§63.10(b)(2)(i)-(iv)	Records Related to Startup, Shutdown, and Malfunction	Occurrence of each for operations (process equipment); occurrence of each malfunction of air pollution control equipment; maintenance on air pollution control equipment; actions during SSM	Yes.
§63.10(b)(2)(vi)-(xi)	CMS Records	Malfunctions, inoperative, out-of-control periods	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting initial notification and notification of compliance status	Yes.
§63.10(b)(3)	Records	Applicability	Yes.

		determinations	
§63.10(c)	Records	Additional records for CMS	Yes.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	SSM Reports	Contents and submission	Yes.
§63.10(e)(1)-(2)	Additional CMS Reports	Must report results for each CEMS on a unit; written copy of CMS performance evaluation; 2-3 copies of COMS performance evaluation	Yes; however, COMS are not applicable.
§63.10(e)(3)(i)-(iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations)	Yes; however, note that the title of the report is the compliance report; deviations include excess emissions and parameter exceedances.
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions or parameter monitoring exceedance (now defined as deviations); provision to request semiannual reporting after compliance for 1 year; submit report by 30th day following end of quarter or calendar half; if there has not been an exceedance or excess emissions (now defined as deviations), report contents	Yes.

		in a statement that there have been no deviations; must submit report containing all of the information in §§63.8(c)(7)-(8) and 63.10(c)(5)-(13)	
§63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for CMS (now called deviations); requires all of the information in §§63.10(c)(5)-(13) and 63.8(c)(7)-(8)	Yes.
§63.10(e)(4)	Reporting COMS Data	Must submit COMS data with performance test data	No.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11(b)	Flares	Requirements for flares	Yes; §63.987 requirements apply, and the section references §63.11(b).
§63.11(c), (d), and (e)	Control and work practice requirements	Alternative work practice for equipment leaks	Yes.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

[69 FR 5063, Feb. 3, 2004, as amended at 71 FR 20463, Apr. 20, 2006; 71 FR 42924, July 28, 2006; 73 FR 78215, Dec. 22, 2008]

Appendix R

§ 63.6580

- 63.8802 What methods must I use to demonstrate compliance with the emission limitation for loop slitter adhesive use?
63.8806 How do I demonstrate initial compliance with the emission limitations?

CONTINUOUS COMPLIANCE REQUIREMENTS

- 63.8810 How do I monitor and collect data to demonstrate continuous compliance?
63.8812 How do I demonstrate continuous compliance with the emission limitations?

NOTIFICATIONS, REPORTS, AND RECORDS

- 63.8816 What notifications must I submit and when?
63.8818 What reports must I submit and when?
63.8820 What records must I keep?
63.8822 In what form and how long must I keep my records?

OTHER REQUIREMENTS AND INFORMATION

- 63.8826 What parts of the General Provisions apply to me?
63.8828 Who implements and enforces this subpart?
63.8830 What definitions apply to this subpart?

TABLE 1 TO SUBPART MMMMM OF PART 63—EMISSION LIMITS

TABLE 2 TO SUBPART MMMMM OF PART 63—OPERATING LIMITS FOR NEW OR RECONSTRUCTED FLAME LAMINATION AFFECTED SOURCES

TABLE 3 TO SUBPART MMMMM OF PART 63—PERFORMANCE TEST REQUIREMENTS FOR NEW OR RECONSTRUCTED FLAME LAMINATION AFFECTED SOURCES

TABLE 4 TO SUBPART MMMMM OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITS

TABLE 5 TO SUBPART MMMMM OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITS AND OPERATING LIMITS

TABLE 6 TO SUBPART MMMMM OF PART 63—REQUIREMENTS FOR REPORTS

TABLE 7 TO SUBPART MMMMM OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART MMMMM

AUTHORITY: 42 U.S.C. 7401 *et seq.*

SOURCE: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

40 CFR Ch. I (7–1–14 Edition)

WHAT THIS SUBPART COVERS

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence,

you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than

500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500

brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable

§ 63.6600

40 CFR Ch. I (7–1–14 Edition)

notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

EMISSION AND OPERATING LIMITATIONS

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the

gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which

apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to

the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal

§ 63.6604

40 CFR Ch. I (7–1–14 Edition)

to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the

stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained)

Environmental Protection Agency

§ 63.6610

prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

GENERAL COMPLIANCE REQUIREMENTS

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation 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, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

TESTING AND INITIAL COMPLIANCE REQUIREMENTS

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

§ 63.6611

40 CFR Ch. I (7–1–14 Edition)

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously con-

ducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP

Environmental Protection Agency

§ 63.6620

located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 1})$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide

(CO₂). If pollutant concentrations are to be corrected to 15 percent oxygen and CO₂ concentration is measured in lieu of oxygen concentration measurement, a CO₂ correction factor is needed. Calculate the CO₂ correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 2})$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO₂ volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

F_c = Ratio of the volume of CO₂ produced to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu)

(ii) Calculate the CO₂ correction factor for correcting measurement data to 15 percent O₂, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (\text{Eq. 3})$$

Where:

X_{CO2} = CO₂ correction factor, percent.

5.9 = 20.9 percent O₂—15 percent O₂, the defined O₂ correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O₂ using CO₂ as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2 .

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO_2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.*, operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.*, wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices

used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O₂ or CO₂ according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, ana-

lyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO₂ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) 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 (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and record-keeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you

must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of

the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine

owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

CONTINUOUS COMPLIANCE REQUIREMENTS

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist

of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine

burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not op-

erate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribu-

tion limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

NOTIFICATIONS, REPORTS, AND RECORDS

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following:

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you

must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending

Environmental Protection Agency

§ 63.6650

on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report

must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance

report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

Environmental Protection Agency

§ 63.6655

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Ad-

ministrator at the appropriate address listed in § 63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each

§ 63.6660

40 CFR Ch. I (7–1–14 Edition)

emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

OTHER REQUIREMENTS AND INFORMATION

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary

Environmental Protection Agency

§ 63.6675

RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(1)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids 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. For the purposes of this subpart, the point at which such liquids or

natural gas enters a natural gas processing plant is a point of custody transfer.

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 limitation or operating limitation;

(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 limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO₂.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the

criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or

commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO₂, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control

equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other

place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen con-

tent of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

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.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second

stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

TABLE 1a TO SUBPART ZZZZ OF PART 63—EMISSION LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SPARK IGNITION, 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	<p>a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or.</p> <p>b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O₂.</p>	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ¹

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

TABLE 1b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SI 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
<p>1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or</p> <p>existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O₂ and using NSCR;</p> <p>2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or</p> <p>existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O₂ and not using NSCR.</p>	<p>a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and</p> <p>b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.¹</p> <p>Comply with any operating limitations approved by the Administrator.</p>

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 2b

TABLE 2a TO SUBPART ZZZZ OF PART 63—EMISSION LIMITATIONS FOR NEW AND RE-CONSTRUCTED 2SLB AND COMPRESSION IGNITION STATIONARY RICE >500 HP AND NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of start-up . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O ₂ . If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O ₂ until June 15, 2007.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ¹
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O ₂ .	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbv or less at 15 percent O ₂ .	

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

TABLE 2b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR NEW AND RE-CONSTRUCTED 2SLB AND CI STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, EXISTING CI STATIONARY RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. ¹
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. ¹

Pt. 63, Subpt. ZZZZ, Table 2c

40 CFR Ch. I (7–1–14 Edition)

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
<p>3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE \geq250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and</p> <p>New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE \geq250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and</p> <p>existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.</p>	Comply with any operating limitations approved by the Administrator.

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

TABLE 2c TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING COMPRESSION IGNITION STATIONARY RICE LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS AND EXISTING SPARK IGNITION STATIONARY RICE \leq 500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE \leq 500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE ¹ .	<p>a. Change oil and filter every 500 hours of operation or annually, whichever comes first.²</p> <p>b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;</p> <p>c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³</p>	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ³
2. Non-Emergency, non-black start stationary CI RICE <100 HP.	<p>a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.²</p> <p>b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;</p> <p>c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.³</p>	
3. Non-Emergency, non-black start CI stationary RICE 100 \leq HP \leq 300 HP.	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O ₂ .	
4. Non-Emergency, non-black start CI stationary RICE 300<HP \leq 500.	<p>a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O₂; or</p> <p>b. Reduce CO emissions by 70 percent or more.</p>	
5. Non-Emergency, non-black start stationary CI RICE >500 HP.	<p>a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O₂; or</p> <p>b. Reduce CO emissions by 70 percent or more.</p>	

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 2c

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
6. Emergency stationary SI RICE and black start stationary SI RICE. ¹	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. ³	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. ³	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O ₂ .	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O ₂ .	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500.	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O ₂ .	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O ₂ .	

¹ If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

² Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

³ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤ 300 HP.	<ul style="list-style-type: none"> a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;¹ b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE $300 < \text{HP} \leq 500$.	<ul style="list-style-type: none"> a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more. 	
3. Non-Emergency, non-black start CI stationary RICE > 500 HP.	<ul style="list-style-type: none"> a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O₂; or b. Reduce CO emissions by 70 percent or more. 	
4. Emergency stationary CI RICE and black start stationary CI RICE. ²	<ul style="list-style-type: none"> a. Change oil and filter every 500 hours of operation or annually, whichever comes first;¹ b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE > 500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE > 500 HP that operate 24 hours or less per calendar year. ²	<ul style="list-style-type: none"> a. Change oil and filter every 500 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 	
6. Non-emergency, non-black start 2SLB stationary RICE.	<ul style="list-style-type: none"> a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. 	
7. Non-emergency, non-black start 4SLB stationary RICE ≤ 500 HP.	<ul style="list-style-type: none"> a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. 	

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 2d

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP.	<ul style="list-style-type: none"> a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary. 	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP.	<ul style="list-style-type: none"> a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. 	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP.	<ul style="list-style-type: none"> a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary. 	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	<ul style="list-style-type: none"> a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;¹ b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. 	

¹Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

²If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

40 CFR Ch. I (7-1-14 Edition)

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

¹ After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semi-annual performance tests.

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. reduce CO emissions.	<p>i. Select the sampling port location and the number/ location of traverse points at the inlet and outlet of the control device; and</p> <p>ii. Measure the O₂ at the inlet and outlet of the control device; and</p>	<p>.....</p> <p>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)^{a,c} (heated probe not necessary).</p>	<p>(a) For CO and O₂ measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</p> <p>(b) Measurements to determine O₂ must be made at the same time as the measurements for CO concentration.</p>

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 4

TABLE 4 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE.	a. reduce formaldehyde emissions.	iii. Measure the CO at the inlet and the outlet of the control device.	(1) ASTM D6522–00 (Reapproved 2005) ^{a b c} (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A–4.	(c) The CO concentration must be at 15 percent O ₂ , dry basis.
		i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and	(a) For formaldehyde, O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O ₂ at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM Method D6522–00 (Reapproved 2005) ^a (heated probe not necessary).	(a) Measurements to determine O ₂ concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A–3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 ^a .	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03 ^a , provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device.	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A–7.	(a) THC concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

TABLE 4 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
3. Stationary RICE.	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	<p>i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and</p> <p>ii. Determine the O₂ concentration of the stationary RICE exhaust at the sampling port location; and</p> <p>iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and</p> <p>iv. Measure formaldehyde at the exhaust of the stationary RICE; or</p> <p>v. measure CO at the exhaust of the stationary RICE.</p>	<p>.....</p> <p>(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM Method D6522–00 (Reapproved 2005)^a (heated probe not necessary).</p> <p>(1) Method 4 of 40 CFR part 60, appendix A–3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03^a.</p> <p>(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03^a, provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.</p> <p>(1) Method 10 of 40 CFR part 60, appendix A–4, ASTM Method D6522–00 (2005)^{a,c}, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03^a.</p>	<p>(a) For formaldehyde, CO, O₂, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ("3-point long line"). If the duct is >12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at "3-point long line"; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.</p> <p>(a) Measurements to determine O₂ concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.</p> <p>(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.</p> <p>(a) Formaldehyde concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p> <p>(a) CO concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</p>

^a You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

^b You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 5

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and not using oxidation catalyst.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O ₂ or CO ₂ at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.

Pt. 63, Subpt. ZZZZ, Table 5

40 CFR Ch. I (7–1–14 Edition)

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O ₂ or CO ₂ at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O ₂ , dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O ₂ , dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 5

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
<p>11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.</p> <p>12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.</p> <p>13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.</p> <p>14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.</p>	<p>a. Reduce CO emissions</p> <p>a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.</p> <p>a. Install an oxidation catalyst</p> <p>a. Install NSCR</p>	<p>iii. You have recorded the approved operating parameters (if any) during the initial performance test.</p> <p>i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.</p> <p>i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.</p> <p>i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O₂;</p> <p>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.</p> <p>i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O₂, or the average reduction of emissions of THC is 30 percent or more;</p> <p>ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.</p>

[78 FR 6712, Jan. 30, 2013]

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved ^a ; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved ^a ; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS.	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 6

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
6. Non-emergency 4SRB stationary RICE with a brake HP $\geq 5,000$ located at a major source of HAP.	a. Reduce formaldehyde emissions	<ul style="list-style-type: none"> ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test. <p>Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.^a</p>
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	<ul style="list-style-type: none"> i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit^a; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	<ul style="list-style-type: none"> i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit^a; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
<p>9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE.</p> <p>10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.</p>	<p>a. Work or Management practices</p>	<p>i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or</p> <p>ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.</p>
<p>11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.</p>	<p>a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst.</p>	<p>i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and</p> <p>ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and</p> <p>iii. Reducing these data to 4-hour rolling averages; and</p> <p>iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and</p> <p>v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.</p>
	<p>a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst.</p>	<p>i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and</p> <p>ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and</p> <p>iii. Reducing these data to 4-hour rolling averages; and</p> <p>iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.</p>

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 6

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
12. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst.	<ul style="list-style-type: none"> i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst.	<ul style="list-style-type: none"> i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install an oxidation catalyst	<ul style="list-style-type: none"> i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O₂; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.

Pt. 63, Subpt. ZZZZ, Table 7

40 CFR Ch. I (7–1–14 Edition)

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install NSCR	<p>i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O₂, or the average reduction of emissions of THC is 30 percent or more; and either</p> <p>ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or</p> <p>iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.</p>

^a After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semi-annual performance tests.

[78 FR 6715, Jan. 30, 2013]

TABLE 7 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR REPORTS

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	Compliance report	<p>a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or</p> <p>b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or</p> <p>c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).</p>	<p>i. Semiannually according to the requirements in § 63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and</p> <p>ii. Annually according to the requirements in § 63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations.</p> <p>i. Semiannually according to the requirements in § 63.6650(b).</p> <p>i. Semiannually according to the requirements in § 63.6650(b).</p>

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 8

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and c. Any problems or errors suspected with the meters.	i. Annually, according to the requirements in § 63.6650. i. See item 2.a.i. i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii).	Report	a. The information in § 63.6650(h)(1).	i. annually according to the requirements in § 63.6650(h)(2)–(3).

[78 FR 6719, Jan. 30, 2013]

TABLE 8 TO SUBPART ZZZZ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ.

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions.	Yes.	Additional terms defined in § 63.6675.
§ 63.2	Definitions	Yes	
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention.	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources.	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources.	Yes.	
§ 63.6(c)(1)–(2)	Compliance dates for existing sources.	Yes.	
§ 63.6(c)(3)–(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources.	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)–(3)	Use of alternate standard	Yes.	

Pt. 63, Subpt. ZZZZ, Table 8

40 CFR Ch. I (7–1–14 Edition)

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(h)	Opacity and visible emission standards.	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria.	Yes.	
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests.	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data.	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA.	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting.	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements.	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems.	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance.	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No.	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan.	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	No.	
§ 63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements.	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
§ 63.8(f)(1)–(5)	Alternative monitoring method	Except that § 63.8(e) only applies as specified in § 63.6645. Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test ...	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements.	Yes.	
§ 63.9(b)(1)–(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.

Environmental Protection Agency

Pt. 63, Subpt. ZZZZ, Table 8

General provisions citation	Subject of citation	Applies to sub-part	Explanation
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources.	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test.	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded.	Yes	If alternative is in use.
		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved. Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for record-keeping/reporting.	Yes.	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)–(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA.	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS.	Yes	Except that § 63.10(c)(2)–(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports.	No.	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports.	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

APPENDIX A—PROTOCOL FOR USING AN ELECTROCHEMICAL ANALYZER TO DETERMINE OXYGEN AND CARBON MONOXIDE CONCENTRATIONS FROM CERTAIN ENGINES

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for meas-

uring carbon monoxide (CO) and oxygen (O₂) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O₂).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630–08–0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O ₂)	7782–44–7	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O₂, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O₂ gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or

unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O₂ concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given

cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O₂ and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre-sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day

to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO₂ are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used

to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O₂ concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O₂; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O₂. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O₂) is acceptable for calibration of the O₂ cell. If needed, any lower percentage O₂ calibration gas must be a mixture of O₂ in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O₂ Calibration Gas Concentration.

Select an O₂ gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O₂. When the average exhaust gas O₂ readings are above 6 percent, you may use dry ambient air (20.9 percent O₂) for the up-scale O₂ calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO₂).

8.0 SAMPLE COLLECTION AND ANALYSIS

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbo-charger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O₂ concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that

does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O₂ and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O₂ for the O₂ channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O₂, whichever is less restrictive, respectively.

The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O₂, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O₂ concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO₂ gas standards that are

generally recognized as representative of diesel-fueled engine NO and NO₂ emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO₂ interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentra-

tions from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

- (1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.
- (2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.
- (3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.
- (4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1–4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Run Type:	Facility	Engine I.D.	Date	Pre-Sample Calibration		Stack Gas Sample		Post-Sample Cal. Check	Repeatability Check	
(X)	2	3	4	4	Time	Scrub. OK	Flow- Rate
				O ₂	O ₂	CO	O ₂			
Run #	1	1								
Gas	O ₂	CO								
Sample Cond.										
Phase										
"										
"										
"										
Measurement										
Data Phase										
"										
"										
"										
"										
"										
"										
"										
"										
Mean										
Refresh										
Phase										
"										
"										
"										
"										

[78 FR 6721, Jan. 30, 2013]

Appendix S

Environmental Protection Agency

§ 63.7491

Citation	Subject	Applies to Subpart CCCCC?	Explanation
§ 63.10(c)(7)–(8)	Records of Excess Emissions and Parameter Monitoring Exceedances for CMS.	No	Subpart CCCCC specifies record requirements.
§ 63.10(e)(3)	Excess Emission Reports	No	Subpart CCCCC specifies reporting requirements.
§ 63.11	Control Device Requirements	No	Subpart CCCCC does not require flares.
§ 63.12	State Authority and Delegations.	Yes.	
§§ 63.13–63.15	Addresses, Incorporation by Reference, Availability of Information.	Yes.	

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

WHAT THIS SUBPART COVERS

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

[78 FR 7162, Jan. 31, 2013]

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected

sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to be revised.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after

Environmental Protection Agency

§ 63.7500

January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7495 was amended by adding paragraph (e). However, there is already a paragraph (e).

EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

- (a) Pulverized coal/solid fossil fuel units.
- (b) Stokers designed to burn coal/solid fossil fuel.
- (c) Fluidized bed units designed to burn coal/solid fossil fuel.
- (d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.
- (e) Fluidized bed units designed to burn biomass/bio-based solid.
- (f) Suspension burners designed to burn biomass/bio-based solid.
- (g) Fuel cells designed to burn biomass/bio-based solid.
- (h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.
- (i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.
- (j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.
- (k) Units designed to burn liquid fuel that are non-continental units.
- (l) Units designed to burn gas 1 fuels.
- (m) Units designed to burn gas 2 (other) gases.
- (n) Metal process furnaces.
- (o) Limited-use boilers and process heaters.
- (p) Units designed to burn solid fuel.
- (q) Units designed to burn liquid fuel.
- (r) Units designed to burn coal/solid fossil fuel.
- (s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and

§ 63.7501

40 CFR Ch. I (7–1–14 Edition)

before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers

and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

Environmental Protection Agency

§ 63.7505

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compli-

ance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7163, Jan. 31, 2013]

GENERAL COMPLIANCE REQUIREMENTS

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies

to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

TESTING, FUEL ANALYSES, AND INITIAL COMPLIANCE REQUIREMENTS

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for start-up, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas,

refinery gas, or other gas 1 fuels are cofired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance test-

ing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

[78 FR 7164, Jan. 31, 2013]

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecu-

tive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61

months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and ac-

cording to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

[78 FR 7165, Jan. 31, 2013]

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for

multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

Environmental Protection Agency

§ 63.7521

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section

with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those re-

quired by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to

the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013]

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging

option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if

you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hm) \div \sum_{i=1}^n Hm \quad (\text{Eq. 1a})$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for

PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 1b})$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel anal-

ysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 1c})$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this sub-

part, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

Environmental Protection Agency

§ 63.7522

n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to

using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sm \times Cfi) \div \sum_{i=1}^n (Sm \times Cfi) \quad (\text{Eq. 2})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to para-

graphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Hb) \div \sum_{i=1}^n Hb \quad (\text{Eq. 3a})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission

rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times So) \div \sum_{i=1}^n So \quad (\text{Eq. 3b})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel anal-

ysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} , determined according to § 63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Eo) \div \sum_{i=1}^n Eo \quad (\text{Eq. 3c})$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj} ,

determined according to § 63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^n (Er \times Sa \times Cfi) \div \sum_{i=1}^n (Sa \times Cfi) \quad (\text{Eq. 4})$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission

rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units

Environmental Protection Agency

§ 63.7522

of million Btu of heat input per pounds of steam generated for boiler, i.
1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month.

After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$E_{avg} = \sum_{i=1}^n E_{Ri} \div 12 \quad (\text{Eq. 5})$$

Where:

E_{avg} = 12-month rolling average emission rate, (pounds per million Btu heat input)
 E_{Ri} = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from

multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if

you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^n (ELi \times Hi) \div \sum_{i=1}^n Hi \quad (\text{Eq. 6})$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8

to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013]

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy

testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are

unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the ex-

haust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamperes.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamperes.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamperes).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform

Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see <http://www.epa.gov/ttn/chief/ert/erttool.html>).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's speci-

fied maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (*e.g.*, weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily be recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the

mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (1)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (1)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later than 180 days after the date of initial startup.

(iii) No later than 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (1)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later than 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix

A–7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO₂) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO₂ CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO₂ CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO₂ CEMS must meet the applicable daily, quarterly, and semi-annual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter

if the SO₂ CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO₂ data, you must operate the SO₂ CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO₂ data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO₂ concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO₂ data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating

Environmental Protection Agency

§ 63.7530

limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^n (Ci \times Qi) \quad (\text{Eq. 7})$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level

(Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^n (HGi \times Qi) \quad (\text{Eq. 8})$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heat-

er through fuels burned in units of pounds per million Btu.

§ 63.7530

40 CFR Ch. I (7–1–14 Edition)

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels

during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSM_{input} = \sum_{i=1}^n (TSM_i \times Q_i) \quad (\text{Eq. 9})$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during

which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a

new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(1) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(2) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(3) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values cor-

responding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(1) through (4) of this section.

(1) Determine your instrument zero output with one of the following procedures:

(i) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(iii) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(iv) If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of this section are possible, you must use a zero output value provided by the manufacturer.

(2) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n} \sum_{i=1}^n X_i, \bar{Y} = \frac{1}{n} \sum_{i=1}^n Y_i \quad (\text{Eq. 10})$$

Where:

X_i = the PM CPMS data points for the three runs constituting the performance test,

Y_i = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(3) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \quad (\text{Eq. 11})$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(4) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_1 = z + \frac{0.75(L)}{R} \quad (\text{Eq. 12})$$

Where:

O_1 = the operating limit for your PM CPMS on a 30-day rolling average, in milliamperes.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamperes, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you

must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n} \sum_{i=1}^n X_i \quad (\text{Eq. 13})$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamperes.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate

continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamperes) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30\text{-day} = \frac{\sum_{i=1}^n Hpv_i}{n} \quad (\text{Eq. 14})$$

Where:

30-day = 30-day average.

Hpv_i = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instrument's primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate

compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag

§ 63.7530

40 CFR Ch. I (7–1–14 Edition)

leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO₂ CEMS is to install and operate the SO₂ according to the requirements in § 63.7525(m) establish a maximum SO₂ emission rate equal to the highest hourly average SO₂ measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = \text{mean} + (SD \times t) \quad (\text{Eq. 15})$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{\alpha,i}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^n (Ci90 \times Qi \times 1.028) \quad (\text{Eq. 16})$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If

you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that

Environmental Protection Agency**§ 63.7530**

you calculate for your boiler or process heater using Equation 17 of this section

must not exceed the applicable emission limit for mercury.

$$\text{Mercury} = \sum_{i=1}^n (Hgi90 \times Qi) \quad (\text{Eq. 17})$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$\text{Metals} = \sum_{i=1}^n (TSM90i \times Qi) \quad (\text{Eq. 18})$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment

was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2

or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO₂ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO₂ CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO₂ operating limit by collecting the minimum hourly SO₂ emission rate on the SO₂ CEMS during the paired 3-run test for HCl. The maximum SO₂ operating limit is equal to the highest hourly average SO₂ concentration measured during the most recent HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013]

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of

this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.*, fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1,

2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^n EIS_{iactual} \right) \div EI_{baseline} \quad (\text{Eq. 19})$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i , implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures

implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad (\text{Eq. 20})$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013]

CONTINUOUS COMPLIANCE REQUIREMENTS

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. 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 or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) 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, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or re-established during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in

§ 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated

and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with

continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720

hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must con-

duct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and

reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must

return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013]

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

NOTIFICATION, REPORTS, AND RECORDS

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate

initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to § 63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1

fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change

Environmental Protection Agency

§ 63.7550

resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the com-

pliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that dem-

onstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the

CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)–(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in § 63.2) you must submit the relative accuracy test

audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

[78 FR 7183, Jan. 31, 2013]

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013]

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

Environmental Protection Agency

§ 63.7575

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

OTHER REQUIREMENTS AND INFORMATION

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analyt-

ical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and

objectively evaluated in a judicial or administrative proceeding.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not in-

tended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of

higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) 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.

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incor-

porated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In

addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr

plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-

conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA

method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal,

sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes

place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a

major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate

boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the antici-

pated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

- (i) Boiler combustion management.
- (ii) Boiler thermal energy recovery, including
 - (A) Conventional feed water economizer,
 - (B) Conventional combustion air preheater, and
 - (C) Condensing economizer.
- (iii) Boiler blowdown thermal energy recovery.
- (iv) Primary energy resource selection, including
 - (A) Fuel (primary energy source) switching, and
 - (B) Applied steam energy versus direct-fired energy versus electricity.

- (v) Insulation issues.
- (vi) Steam trap and steam leak management.
- (vi) Condensate recovery.
- (viii) Steam end-use management.
- (2) Capabilities and knowledge includes, but is not limited to:
 - (i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.
 - (ii) Familiarity with operating and maintenance practices for steam or process heating systems.
 - (iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.
 - (iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.
 - (v) Boiler-steam turbine cogeneration systems.
 - (vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

- (1) A dwelling containing four or fewer families; or
- (2) A single unit residence dwelling that has since been converted or sub-

divided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

- (1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad (\text{Eq. 21})$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad (\text{Eq. 22})$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad (\text{Eq. 23})$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad (\text{Eq. 24})$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{\text{OBE}} = EL_{\text{T}} \times 10.4 \text{ MMBtu/Mwh} \quad (\text{Eq. 25})$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_{T} = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory

where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr

Environmental Protection Agency

§ 63.7575

Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, +61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not pre-

clude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (*i.e.*, hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (*e.g.*, thermal oxidizer, kiln, furnace) or power (*e.g.*, combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (*i.e.*, hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

As stated in § 63.7500, you must comply with the following applicable emission limits:
[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E–07 ^a lb per MMBtu of heat input.	8.7E–07 ^a lb per MMBtu of steam output or 1.1E–05 ^a lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.2E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 1

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input).	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input).	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 ^a lb per MMBtu of heat input).	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 ^a lb per MMBtu of steam output or 1.2E-03 ^a lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input).	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh).	Collect a minimum of 2 dscm per run.

Pt. 63, Subpt. DDDDD, Table 1

40 CFR Ch. I (7–1–14 Edition)

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	3.5E–01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 ^a lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 ^a lb per MMBtu of heat input.	5.3E–07 ^a lb per MMBtu of steam output or 6.7E–06 ^a lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 1

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
16. Units designed to burn light liquid fuel.	b. Filterable PM (or TSM).	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input).	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh).	Collect a minimum of 3 dscm per run.
	a. CO b. Filterable PM (or TSM).	130 ppm by volume on a dry basis corrected to 3 percent oxygen. 1.1E-03 ^a lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input).	0.13 lb per MMBtu of steam output or 1.4 lb per MWh. 1.2E-03 ^a lb per MMBtu of steam output or 1.6E-02 ^a lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh).	1 hr minimum sampling time. Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO b. Filterable PM (or TSM).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test. 2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input).	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average. 2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh).	1 hr minimum sampling time. Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO b. HCl c. Mercury d. Filterable PM (or TSM).	130 ppm by volume on a dry basis corrected to 3 percent oxygen. 1.7E-03 lb per MMBtu of heat input. 7.9E-06 lb per MMBtu of heat input. 6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input).	0.16 lb per MMBtu of steam output or 1.0 lb per MWh. 2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh. 1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh. 1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh).	1 hr minimum sampling time. For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run. For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm. Collect a minimum of 3 dscm per run.

^a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

^b Incorporated by reference, see §63.14.

^c If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[78 FR 7193, Jan. 31, 2013]

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

As stated in § 63.7500, you must comply with the following applicable emission limits:
[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 2

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input).	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input).	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input).	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh).	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input).	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh).	Collect a minimum of 2 dscm per run.

Pt. 63, Subpt. DDDDD, Table 2

40 CFR Ch. I (7–1–14 Edition)

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	8.4E–01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06 lb per MMBtu of heat input.	2.5E–06 lb per MMBtu of steam output or 2.8E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 ^b collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 2

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this sub-category . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
16. Units designed to burn light liquid fuel.	b. Filterable PM (or TSM).	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input).	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh).	Collect a minimum of 1 dscm per run.
	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input).	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input).	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input.	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input.	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 2 dscm.
	d. Filterable PM (or TSM).	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input).	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh).	Collect a minimum of 3 dscm per run.

^a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

^b Incorporated by reference, see § 63.14.

[78 F.R. 7195, Jan. 31, 2013]

Pt. 63, Subpt. DDDDD, Table 3

40 CFR Ch. I (7–1–14 Edition)

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: <ul style="list-style-type: none"> a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 4

If your unit is . . .	You must meet the following . . .
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown.	<p>If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.</p> <p>You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.</p> <p>You must operate all CMS during shutdown.</p> <p>While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.</p> <p>You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.</p>

[78 FR 7198, Jan. 31, 2013]

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS.	<p>a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or</p> <p>b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.</p>
4. Electrostatic precipitator control on units not using a PM CPMS.	<p>a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or</p> <p>b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.</p>
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).

Pt. 63, Subpt. DDDDD, Table 5

40 CFR Ch. I (7–1–14 Edition)

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to §63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O ₂ analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).
10. SO ₂ CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO ₂ CEMS, maintain the 30-day rolling average SO ₂ emission rate at or below the highest hourly average SO ₂ concentration measured during the most recent HCl performance test, as specified in Table 8.

[78 FR 7199, Jan. 31, 2013]

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

As stated in §63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant...	You must...	Using...
1. Filterable PM	<ul style="list-style-type: none"> a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas. e. Measure the PM emission concentration f. Convert emissions concentration to lb per MMBtu emission rates. 	<ul style="list-style-type: none"> Method 1 at 40 CFR part 60, appendix A–1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.^a Method 4 at 40 CFR part 60, appendix A–3 of this chapter. Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter. Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. TSM	<ul style="list-style-type: none"> a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas. e. Measure the TSM emission concentration. f. Convert emissions concentration to lb per MMBtu emission rates. 	<ul style="list-style-type: none"> Method 1 at 40 CFR part 60, appendix A–1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.^a Method 4 at 40 CFR part 60, appendix A–3 of this chapter. Method 29 at 40 CFR part 60, appendix A–8 of this chapter Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. Hydrogen chloride	<ul style="list-style-type: none"> a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen or carbon dioxide concentration of the stack gas. d. Measure the moisture content of the stack gas. e. Measure the hydrogen chloride emission concentration. 	<ul style="list-style-type: none"> Method 1 at 40 CFR part 60, appendix A–1 of this chapter. Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter. Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.^a Method 4 at 40 CFR part 60, appendix A–3 of this chapter. Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 6

To conduct a performance test for the following pollutant...	You must...	Using...
4. Mercury	<p>f. Convert emissions concentration to lb per MMBtu emission rates.</p> <p>a. Select sampling ports location and the number of traverse points.</p> <p>b. Determine velocity and volumetric flow-rate of the stack gas.</p> <p>c. Determine oxygen or carbon dioxide concentration of the stack gas.</p> <p>d. Measure the moisture content of the stack gas.</p> <p>e. Measure the mercury emission concentration.</p>	<p>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</p> <p>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</p> <p>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.</p> <p>Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.^a</p> <p>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</p> <p>Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.^a</p>
5. CO	<p>f. Convert emissions concentration to lb per MMBtu emission rates.</p> <p>a. Select the sampling ports location and the number of traverse points.</p> <p>b. Determine oxygen concentration of the stack gas.</p> <p>c. Measure the moisture content of the stack gas.</p> <p>d. Measure the CO emission concentration</p>	<p>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</p> <p>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</p> <p>Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.^a</p> <p>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</p> <p>Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.</p>

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013]

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	<p>a. Collect fuel samples</p> <p>b. Composite fuel samples</p> <p>c. Prepare composited fuel samples</p> <p>d. Determine heat content of the fuel type.</p> <p>e. Determine moisture content of the fuel type.</p> <p>f. Measure mercury concentration in fuel sample.</p> <p>g. Convert concentration into units of pounds of mercury per MMBtu of heat content.</p>	<p>Procedure in § 63.7521(c) or ASTM D5192^a, or ASTM D7430^a, or ASTM D6863^a, or ASTM D2234/D2234M^a(for coal) or EPA 1631 or EPA 1631E or ASTM D6323^a (for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177^a (for liquid), or ASTM D4057^a (for liquid), or equivalent.</p> <p>Procedure in § 63.7521(d) or equivalent.</p> <p>EPA SW-846-3050B^a (for solid samples), EPA SW-846-3020A^a (for liquid samples), ASTM D2013/D2013M^a (for coal), ASTM D5198^a (for biomass), or EPA 3050^a (for solid fuel), or EPA 821-R-01-013^a (for liquid or solid), or equivalent.</p> <p>ASTM D5865^a (for coal) or ASTM E711^a (for biomass), or ASTM D5864^a for liquids and other solids, or ASTM D240^a or equivalent.</p> <p>ASTM D3173^a, ASTM E871^a, or ASTM D5864^a, or ASTM D240, or ASTM D95^a (for liquid fuels), or ASTM D4006^a (for liquid fuels), or ASTM D4177^a (for liquid fuels) or ASTM D4057^a (for liquid fuels), or equivalent.</p> <p>ASTM D6722^a (for coal), EPA SW-846-7471B^a (for solid samples), or EPA SW-846-7470A^a (for liquid samples), or equivalent.</p> <p>Equation 8 in § 63.7530.</p>

Pt. 63, Subpt. DDDDD, Table 6

40 CFR Ch. I (7–1–14 Edition)

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
2. HCl	<p>h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.</p> <p>a. Collect fuel samples</p> <p>b. Composite fuel samples</p> <p>c. Prepare composited fuel samples</p> <p>d. Determine heat content of the fuel type.</p> <p>e. Determine moisture content of the fuel type.</p> <p>f. Measure chlorine concentration in fuel sample.</p> <p>g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.</p> <p>h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu.</p>	<p>Equations 10 and 12 in § 63.7530.</p> <p>Procedure in § 63.7521(c) or ASTM D5192^a, or ASTM D7430^a, or ASTM D6883^a, or ASTM D2234/ D2234M^a (for coal) or ASTM D6323^a (for coal or biomass), ASTM D4177^a (for liquid fuels) or ASTM D4057^a (for liquid fuels), or equivalent.</p> <p>Procedure in § 63.7521(d) or equivalent.</p> <p>EPA SW-846-3050B^a (for solid samples), EPA SW-846-3020A^a (for liquid samples), ASTM D2013/ D2013M^a (for coal), or ASTM D5198^a (for biomass), or EPA 3050^a or equivalent.</p> <p>ASTM D5865^a (for coal) or ASTM E711^a (for biomass), ASTM D5864, ASTM D240^a or equivalent.</p> <p>ASTM D3173^a or ASTM E871^a, or D5864^a, or ASTM D240^a, or ASTM D95^a (for liquid fuels), or ASTM D4006^a (for liquid fuels), or ASTM D4177^a (for liquid fuels) or ASTM D4057^a (for liquid fuels) or equivalent.</p> <p>EPA SW-846-9250^a, ASTM D6721^a, ASTM D4208^a (for coal), or EPA SW-846-5050^a or ASTM E776^a (for solid fuel), or EPA SW-846-9056^a or SW-846-9076^a (for solids or liquids) or equivalent.</p> <p>Equation 7 in § 63.7530.</p> <p>Equations 10 and 11 in § 63.7530.</p>
3. Mercury Fuel Specification for other gas 1 fuels.	<p>a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter.</p> <p>b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.</p>	<p>Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954^a, ASTM D6350^a, ISO 6978-1:2003(E)^a, or ISO 6978-2:2003(E)^a, or EPA-1631^a or equivalent.</p> <p>Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784^a or equivalent.</p>
4. TSM for solid fuels	<p>a. Collect fuel samples</p> <p>b. Composite fuel samples</p> <p>c. Prepare composited fuel samples</p> <p>d. Determine heat content of the fuel type.</p> <p>e. Determine moisture content of the fuel type.</p> <p>f. Measure TSM concentration in fuel sample.</p> <p>g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.</p> <p>h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu.</p>	<p>Procedure in § 63.7521(c) or ASTM D5192^a, or ASTM D7430^a, or ASTM D6883^a, or ASTM D2234/ D2234M^a (for coal) or ASTM D6323^a (for coal or biomass), or ASTM D4177^a (for liquid fuels) or ASTM D4057^a (for liquid fuels), or equivalent.</p> <p>Procedure in § 63.7521(d) or equivalent.</p> <p>EPA SW-846-3050B^a (for solid samples), EPA SW-846-3020A^a (for liquid samples), ASTM D2013/ D2013M^a (for coal), ASTM D5198^a or TAPPI T266^a (for biomass), or EPA 3050^a or equivalent.</p> <p>ASTM D5865^a (for coal) or ASTM E711^a (for biomass), or ASTM D5864^a for liquids and other solids, or ASTM D240^a or equivalent.</p> <p>ASTM D3173^a or ASTM E871^a, or D5864, or ASTM D240^a, or ASTM D95^a (for liquid fuels), or ASTM D4006^a (for liquid fuels), or ASTM D4177^a (for liquid fuels) or ASTM D4057^a (for liquid fuels), or equivalent.</p> <p>ASTM D3683^a, or ASTM D4606^a, or ASTM D6357^a or EPA 200.8^a or EPA SW-846-6020^a, or EPA SW-846-6020A^a, or EPA SW-846-6010C^a, EPA 7060^a or EPA 7060A^a (for arsenic only), or EPA SW-846-7740^a (for selenium only).</p> <p>Equation 9 in § 63.7530.</p> <p>Equations 10 and 13 in § 63.7530.</p>

^aIncorporated by reference, see § 63.14.

[78 F.R. 7201, Jan. 31, 2013]

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury.	<p>a. Wet scrubber operating parameters.</p> <p>b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).</p>	<p>i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).</p> <p>i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).</p>	<p>(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test.</p> <p>(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test.</p>	<p>(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests.</p> <p>(b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests.</p> <p>(b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p>
2. HCl	<p>a. Wet scrubber operating parameters.</p> <p>b. Dry scrubber operating parameters.</p>	<p>i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).</p> <p>i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.</p>	<p>(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test.</p> <p>(1) Data from the sorbent injection rate monitors and HCl or mercury performance test.</p>	<p>(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests.</p> <p>(b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests.</p>

Pt. 63, Subpt. DDDDD, Table 7

40 CFR Ch. I (7–1–14 Edition)

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	c. Alternative Maximum SO ₂ emission rate.	i. Establish a site-specific maximum SO ₂ emission rate operating limit according to § 63.7530(b).	(1) Data from SO ₂ CEMS and the HCl performance test.	<p>(b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.</p> <p>(a) You must collect the SO₂ emissions data according to § 63.7525(m) during the most recent HCl performance tests.</p> <p>(b) The maximum SO₂ emission rate is equal to the lowest hourly average SO₂ emission rate measured during the most recent HCl performance tests.</p>
3. Mercury	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	<p>(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.</p> <p>(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p>

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 7

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	<p>(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.</p> <p>(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.</p> <p>(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.</p>
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	<p>(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.</p> <p>(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.</p>

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7203, Jan. 31, 2013]

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation.	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO ₂ emissions using SO ₂ CEMS	a. Collecting the SO ₂ CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO ₂ CEMS emission rate to a level at or below the minimum hourly SO ₂ rate measured during the most recent HCl performance test according to § 63.7530.

[78 FR 7204, Jan. 31, 2013]

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 10

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	<p>a. Information required in § 63.7550(c)(1) through (5); and</p> <p>b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and</p> <p>c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and</p> <p>d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e).</p>	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c).	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards..	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards..	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.

Pt. 63, Subpt. DDDDD, Table 10

40 CFR Ch. I (7–1–14 Edition)

Citation	Subject	Applies to subpart DDDDD
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns.	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations ..	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions.	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9) ..	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 12

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7206, Jan. 31, 2013, Table 11 was added, effective Apr. 1, 2013. However Table 11 could not be added as a Table 11 is already in existence.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of start-up and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel.	a. Mercury	3.5E-06 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride ...	0.004 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.

Pt. 63, Subpt. DDDDD, Table 12

40 CFR Ch. I (7–1–14 Edition)

If your boiler or process heater is in this sub-category	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of start-up and shutdown	Using this specified sampling volume or test run duration
	b. Hydrogen Chloride ...	0.0022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel.	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
7. Stokers designed to burn biomass/bio-based solids.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride ...	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 12

If your boiler or process heater is in this sub-category	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of start-up and shutdown	Using this specified sampling volume or test run duration
13. Units designed to burn liquid fuel located in non-continental States and territories.	c. Mercury	3.0E-07 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride ...	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E-07 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
14. Units designed to burn gas 2 (other) gases ..	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride ...	0.0017 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^a collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.

Pt. 63, Subpt. DDDDD, Table 13

40 CFR Ch. I (7–1–14 Edition)

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of start-up and shutdown	Using this specified sampling volume or test run duration
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.

^aIncorporated by reference, see § 63.14.

[76 FR 15664, Mar. 21, 2011]

EDITORIAL NOTE: At 78 FR 7208, Jan. 31, 2013, Table 12 was added, effective Apr. 1, 2013. However, Table 12 could not be added as a Table 12 is already in existence.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E–07 ^a lb per MMBtu of heat input.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

Environmental Protection Agency

Pt. 63, Subpt. DDDDD, Table 13

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
6. Stokers/sloped grate/others designed to burn wet biomass fuel.	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
8. Fluidized bed units designed to burn biomass/bio-based solids.	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
9. Suspension burners designed to burn biomass/bio-based solids.	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
11. Fuel cell units designed to burn biomass/bio-based solids.	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
13. Units designed to burn liquid fuel.	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
	a. HCl	1.2E-03 lb per MMBtu of heat input.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

Pt. 63, Subpt. DDDDD, Table 13

40 CFR Ch. I (7–1–14 Edition)

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
14. Units designed to burn heavy liquid fuel.	b. Mercury	4.9E–07 ^a lb per MMBtu of heat input.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 4 dscm. 1 hr minimum sampling time.
	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	
	b. Filterable PM (or TSM)	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130 ^a ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average)..	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 ^a lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 ^b collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

^a If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

^b Incorporated by reference, see § 63.14.

[78 FR 7210, Jan. 31, 2013]

Appendix T

Subpart LLLLL—National Emission Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing

Contents

[What This Subpart Covers](#)

- [§63.8680 What is the purpose of this subpart?](#)
- [§63.8681 Am I subject to this subpart?](#)
- [§63.8682 What parts of my plant does this subpart cover?](#)
- [§63.8683 When must I comply with this subpart?](#)

[Emission Limitations](#)

- [§63.8684 What emission limitations must I meet?](#)

[General Compliance Requirements](#)

- [§63.8685 What are my general requirements for complying with this subpart?](#)

[Testing and Initial Compliance Requirements](#)

- [§63.8686 By what date must I conduct performance tests or other initial compliance demonstrations?](#)
- [§63.8687 What performance tests, design evaluations, and other procedures must I use?](#)
- [§63.8688 What are my monitoring installation, operation, and maintenance requirements?](#)
- [§63.8689 How do I demonstrate initial compliance with the emission limitations?](#)

[Continuous Compliance Requirements](#)

- [§63.8690 How do I monitor and collect data to demonstrate continuous compliance?](#)
- [§63.8691 How do I demonstrate continuous compliance with the operating limits?](#)

[Notifications, Reports, and Records](#)

- [§63.8692 What notifications must I submit and when?](#)
- [§63.8693 What reports must I submit and when?](#)
- [§63.8694 What records must I keep?](#)
- [§63.8695 In what form and how long must I keep my records?](#)

[Other Requirements and Information](#)

[§63.8696 What parts of the General Provisions apply to me?](#)
[§63.8697 Who implements and enforces this subpart?](#)
[§63.8698 What definitions apply to this subpart?](#)
[Table 1 to Subpart LLLLL of Part 63—Emission Limitations](#)
[Table 2 to Subpart LLLLL of Part 63—Operating Limits](#)
[Table 3 to Subpart LLLLL of Part 63—Requirements for Performance Tests](#)
[Table 4 to Subpart LLLLL of Part 63—Initial Compliance With Emission Limitations](#)
[Table 5 to Subpart LLLLL of Part 63—Continuous Compliance With Operating Limits](#)
[Table 6 to Subpart LLLLL of Part 63—Requirements for Reports](#)
[Table 7 to Subpart LLLLL of Part 63—Applicability of General Provisions to Subpart LLLLL](#)

SOURCE: 68 FR 24577, May 7, 2003, unless otherwise noted.

[↑ Back to Top](#)

What This Subpart Covers

[↑ Back to Top](#)

§63.8680 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for existing and new asphalt processing and asphalt roofing manufacturing facilities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

[↑ Back to Top](#)

§63.8681 Am I subject to this subpart?

- (a) You are subject to this subpart if you own or operate an asphalt processing facility or an asphalt roofing manufacturing facility, as defined in §63.8698, that is a major source of hazardous air pollutants (HAP) emissions, or is located at, or is part of a major source of HAP emissions.
- (b) After the applicable compliance date specified in §63.8683, blowing stills, asphalt storage tanks, saturators, wet loopers, and coaters subject to the provisions of this subpart that are also subject to 40 CFR part 60, subpart UU, are required to comply only with provisions of this subpart.
- (c) This subpart does not apply to any equipment that is subject to subpart CC of this part or to subpart K, Ka, or Kb of 40 CFR part 60.

(d) This subpart does not apply to asphalt processing and asphalt roofing manufacturing equipment used for research and development, as defined in §63.8698.

(e) The provisions of subpart J of 40 CFR part 60 do not apply to emissions from asphalt processing facilities subject to this subpart.

(f) A major source of HAP emissions is any stationary source or group of stationary sources within a contiguous area under common control that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

[68 FR 24577, May 7, 2003, as amended at 70 FR 28364, May 17, 2005]

[↑ Back to Top](#)

§63.8682 What parts of my plant does this subpart cover?

(a) This subpart applies to each new, reconstructed, or existing affected source at asphalt processing and asphalt roofing manufacturing facilities.

(b) The affected source is:

(1) Each asphalt processing facility as defined in §63.8698; or

(2) Each asphalt roofing manufacturing line as defined in §63.8698.

(i) If the asphalt roofing manufacturing line is collocated with an asphalt processing facility, the storage tanks that store asphalt flux intended for oxidation in the blowing stills and those tanks that receive asphalt directly from the on-site blowing stills are part of the asphalt processing facility. The remaining asphalt storage tanks are considered to be part of the asphalt roofing facility.

(ii) If an asphalt storage tank is shared by two or more lines at an asphalt roofing manufacturing facility, the shared storage tank is considered part of the line to which the tank supplies the greatest amount of asphalt, on an annual basis.

(iii) If a sealant or adhesive applicator is shared by two or more asphalt roofing manufacturing lines, the shared applicator is considered part of the line that provides the greatest throughput to the applicator, on an annual basis.

(c) An affected source is a new affected source if you commenced construction of the affected source after November 21, 2001, and you met the applicability criteria at the time you commenced construction.

(d) An affected source is reconstructed if you meet the criteria in the reconstruction definition in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

[↑ Back to Top](#)

§63.8683 When must I comply with this subpart?

(a) If you have a new or reconstructed affected source and start up:

(1) On or before April 29, 2003, then you must comply with the requirements for new and reconstructed sources in this subpart no later than April 29, 2003.

(2) After April 29, 2003, then you must comply with the requirements for new and reconstructed sources in this subpart upon startup.

(b) If you have an existing affected source, you must comply with the requirements for existing sources no later than May 1, 2006.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a (or part of a) major source of HAP, then the following requirements apply:

(1) Any portion of the existing facility that becomes a new or reconstructed affected source must be in compliance with this subpart upon startup or by April 29, 2003, whichever is later.

(2) All other parts of the source to which this subpart applies must be in compliance with this subpart by 3 years after the date the source becomes a major source.

(d) You must meet the notification requirements in §63.8692 according to the schedules in §§63.8692 and 63.9. Some of the notifications must be submitted before you are required to comply with the emission limitations in this subpart.

[↑ Back to Top](#)

Emission Limitations

[↑ Back to Top](#)

§63.8684 What emission limitations must I meet?

(a) You must meet each emission limitation in Table 1 to this subpart that applies to you.

(b) You must meet each operating limit in Table 2 to this subpart that applies to you.

[↑ Back to Top](#)

General Compliance Requirements

[↑ Back to Top](#)

§63.8685 What are my general requirements for complying with this subpart?

- (a) You must be in compliance with the emission limitations (including operating limits) in this subpart at all times, except during periods of startup, shutdown, and malfunction.
- (b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).
- (c) You must develop a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).
- (d) You must develop and implement a written site-specific monitoring plan according to the provisions in §63.8688(g) and (h).

[68 FR 24577, May 7, 2003, as amended at 71 FR 20469, Apr. 20, 2006]

[↑ Back to Top](#)

Testing and Initial Compliance Requirements

[↑ Back to Top](#)

§63.8686 By what date must I conduct performance tests or other initial compliance demonstrations?

- (a) For existing affected sources, you must conduct performance tests no later than 180 days after the compliance date that is specified for your source in §63.8683 and according to the provisions in §63.7(a)(2).
- (b) As an alternative to the requirement specified in paragraph (a) of this section, you may use the results of a previously-conducted emission test to demonstrate compliance with the emission limitations in this subpart if you demonstrate to the Administrator's satisfaction that:
 - (1) No changes have been made to the process since the time of the emission test; and
 - (2) The operating conditions and test methods used during testing conform to the requirements of this subpart; and

(3) The control device and process parameter values established during the previously-conducted emission test are used to demonstrate continuous compliance with this subpart.

(c) For new sources, you must demonstrate initial compliance no later than 180 calendar days after April 29, 2003 or within 180 calendar days after startup of the source, whichever is later.

[↑ Back to Top](#)

§63.8687 What performance tests, design evaluations, and other procedures must I use?

(a) You must conduct each performance test in Table 3 to this subpart that applies to you.

(b) Each performance test must be conducted under normal operating conditions and under the conditions specified in Table 3 to this subpart.

(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(d) Except for opacity and visible emission observations, you must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e) You must use the following equations to determine compliance with the emission limitations.

(1) To determine compliance with the particulate matter mass emission rate, you must use Equations 1 and 2 of this section as follows:

$$E = M_{PM}/P \quad (\text{Eq. 1})$$

[View or download PDF](#)

Where:

E = Particulate matter emission rate, kilograms of particulate matter per megagram of roofing product manufactured.

M_{PM} = Particulate matter mass emission rate, kilograms per hour, determined using Equation 2.

P = The asphalt roofing product manufacturing rate during the emissions sampling period, including any material trimmed from the final product, megagram per hour.

$$M_{PM} = C * Q * K \quad (\text{Eq. 2})$$

[View or download PDF](#)

Where:

M_{PM} = Particulate matter mass emission rate, kilograms per hour.

C = Concentration of particulate matter on a dry basis, grams per dry standard cubic meter (g/dscm), as measured by the test method specified in Table 3 to this subpart.

Q = Vent gas stream flow rate (dry standard cubic meters per minute) at a temperature of 20 °C as measured by the test method specified in Table 3 to this subpart.

K = Unit conversion constant (0.06 minute-kilogram/hour-gram).

(2) To determine compliance with the total hydrocarbon percent reduction standard, you must use Equations 3 and 4 of this section as follows:

$$RE = \left[(M_{THCi} - M_{THCo}) / (M_{THCi}) \right] * (100) \quad (\text{Eq. 3})$$

[View or download PDF](#)

Where:

RE = Emission reduction efficiency, percent.

M_{THCi} = Mass flow rate of total hydrocarbons entering the control device, kilograms per hour, determined using Equation 4.

M_{THCo} = Mass flow rate of total hydrocarbons exiting the control device, kilograms per hour, determined using Equation 4.

$$M_{THC} = C * Q * K \quad (\text{Eq. 4})$$

[View or download PDF](#)

Where:

M_{THC} = Total hydrocarbon mass flow rate, kilograms per hour.

C = Concentration of total hydrocarbons on a dry basis, parts per million by volume (ppmv), as measured by the test method specified in Table 3 to this subpart.

Q = Vent gas stream flow rate (dscm/minute) at a temperature of 20 °C as measured by the test method specified in Table 3 to this subpart.

K = Unit conversion constant $(1.10E-04 \text{ (ppmv)}^{-1} \text{ (kilogram/dscm)(minute/hour)})$.

(3) To determine compliance with the combustion efficiency standard, you must use Equation 5 of this section as follows:

$$CE = \left[1 - \left(\frac{CO}{CO_2} \right) - \left(\frac{THC}{CO_2} \right) \right] \quad (\text{Eq. 5})$$

[View or download PDF](#)

Where:

CE = Combustion efficiency, percent.

CO = Carbon monoxide concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

CO₂ = Carbon dioxide concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

THC = Total hydrocarbon concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

(4) To determine compliance with the total hydrocarbon destruction efficiency standard for a combustion device that does not use auxiliary fuel, you must use Equation 6 of this section as follows:

$$THC\ DE = \left[\frac{(CO + CO_2)}{(CO + CO_2 + THC)} \right] \quad (\text{Eq. 6})$$

[View or download PDF](#)

Where:

THC DE = THC destruction efficiency, percent.

CO = Carbon monoxide concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

CO₂ = Carbon dioxide concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

THC = Total hydrocarbon concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart.

[68 FR 24577, May 7, 2003, as amended at 70 FR 28364, May 17, 2005]

[↑ Back to Top](#)

§63.8688 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the following:

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period.

(2) To determine the 3-hour average, you must:

(i) Have a minimum of four successive cycles of operation to have a valid hour of data.

(ii) Have valid data from at least three of four equally spaced data values for that hour from a CPMS that is not out-of-control according to your site-specific monitoring plan.

(iii) Determine the 3-hour average of all recorded readings for each operating day, except as stated in §63.8690(c). You must have at least two of the three hourly averages for that period using only hourly average values that are based on valid data (*i.e.*, not from out-of-control periods).

(3) You must record the results of each inspection, calibration, and validation check.

(b) For each temperature monitoring device, you must meet the requirements in paragraph (a) of this section and the following:

(1) Locate the temperature sensor in a position that provides a representative temperature.

(2) For a noncryogenic temperature range, use a temperature sensor with a minimum measurement sensitivity of 2.8 °C or 1.0 percent of the temperature value, whichever is larger.

(3) If a chart recorder is used, it must have a sensitivity in the minor division of at least 20 °F.

(4) Perform an accuracy check at least semiannually or following an operating parameter deviation:

(i) According to the procedures in the manufacturer's documentation; or

(ii) By comparing the sensor output to redundant sensor output; or

(iii) By comparing the sensor output to the output from a calibrated temperature measurement device; or

(iv) By comparing the sensor output to the output from a temperature simulator.

(5) Conduct accuracy checks any time the sensor exceeds the manufacturer's specified maximum operating temperature range or install a new temperature sensor.

(6) At least quarterly or following an operating parameter deviation, perform visual inspections of components if redundant sensors are not used.

(c) For each pressure measurement device, you must meet the requirements of paragraph (a) of this section and the following:

(1) Locate the pressure sensor(s) in, or as close as possible, to a position that provides a representative measurement of the pressure.

(2) Use a gauge with a minimum measurement sensitivity of 0.12 kiloPascals or a transducer with a minimum measurement sensitivity of 5 percent of the pressure range.

(3) Check pressure tap pluggage daily. Perform an accuracy check at least quarterly or following an operating parameter deviation:

(i) According to the procedures in the manufacturer's documentation; or

(ii) By comparing the sensor output to redundant sensor output.

(4) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(5) At least monthly or following an operating parameter deviation, perform a leak check of all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(6) At least quarterly or following an operating parameter deviation, perform visible inspections on all components if redundant sensors are not used.

(d) For monitoring parameters other than temperature and pressure drop, you must install and operate a CPMS to provide representative measurements of the monitored parameters.

(e) For each flare, you must install a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame.

(f) As an option to installing the CPMS specified in paragraph (a) of this section, you may install a continuous emissions monitoring system (CEMS) or a continuous opacity monitoring system (COMS) that meets the requirements specified in §63.8 and the applicable performance specifications of 40 CFR part 60, appendix B.

(g) For each monitoring system required in this section, you must develop and make available for inspection by the permitting authority, upon request, a site-specific monitoring plan that addresses the following:

(1) Installation of the CPMS, CEMS, or COMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction system; and

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(h) In your site-specific monitoring plan, you must also address the following:

(1) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (c)(3), (c)(4)(ii), (c)(7), and (c)(8);

(2) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(3) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(i) You must conduct a performance evaluation of each CPMS, CEMS, or COMS in accordance with your site-specific monitoring plan.

(j) You must operate and maintain the CPMS, CEMS, or COMS in continuous operation according to the site-specific monitoring plan.

[↑ Back to Top](#)

§63.8689 How do I demonstrate initial compliance with the emission limitations?

(a) You must demonstrate initial compliance with each emission limitation that applies to you according to Table 4 to this subpart.

(b) You must establish each site-specific operating limit in Table 2 to this subpart that applies to you according to the requirements in §63.8687 and Table 3 to this subpart.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.8692(e).

[↑ Back to Top](#)

Continuous Compliance Requirements

[↑ Back to Top](#)

§63.8690 How do I monitor and collect data to demonstrate continuous compliance?

- (a) You must monitor and collect data according to this section.
- (b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating. This includes periods of startup, shutdown, and malfunction when the affected source is operating.
- (c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels, nor may such data be used in fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

[↑ Back to Top](#)

§63.8691 How do I demonstrate continuous compliance with the operating limits?

- (a) You must demonstrate continuous compliance with each operating limit in Table 2 to this subpart that applies to you according to test methods specified in Table 5 to this subpart.
- (b) You must report each instance in which you did not meet each operating limit in Table 5 to this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. These instances are deviations from the emission limitations in this subpart. These deviations must be reported according to the requirements in §63.8693.
- (c) [Reserved]
- (d) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

[68 FR 24577, May 7, 2003, as amended at 71 FR 20469, Apr. 20, 2006]

[↑ Back to Top](#)

Notifications, Reports, and Records

[↑ Back to Top](#)

§63.8692 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.6(h)(4) and (5), 63.7(b) and (c), 63.8(f), and 63.9(b) through (f) and (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you start up your affected source before April 29, 2003, you must submit an Initial Notification not later than 120 calendar days after April 29, 2003.

(c) As specified in §63.9(b)(3), if you start up your new or reconstructed affected source on or after April 29, 2003, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, as required in §63.7(b)(1).

(e) If you are required to conduct a performance test, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration as specified in Table 3 or 4 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). You must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test according to §63.10(d)(2).

(f) If you are using data from a previously-conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must submit the test data in lieu of the initial performance test results with the Notification of Compliance Status required under paragraph (e) of this section.

[↑ Back to Top](#)

§63.8693 What reports must I submit and when?

(a) You must submit each report in Table 6 to this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 6 to this subpart and according to the following dates:

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.8683 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.8683.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.8683.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the following information:

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).

(5) If there are no deviations from any emission limitations (emission limit, operating limit, opacity limit, and visible emission limit) that apply to you, a statement that there were no deviations from the emission limitations during the reporting period.

(6) If there were no periods during which the CPMS, CEMS, or COMS was out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CPMS, CEMS, or COMS was out-of-control during the reporting period.

(d) For each deviation from an emission limitation (emission limit, operating limit, opacity limit, and visible emission limit), you must include the information in paragraphs (c)(1) through (6) of this section, and the information in paragraphs (d)(1) through (12) of this section. This includes periods of startup, shutdown, and malfunction.

- (1) The date and time that each malfunction started and stopped.
 - (2) The date and time that each CPMS, CEMS, or COMS was inoperative, except for zero (low-level) and high-level checks.
 - (3) The date, time and duration that each CPMS, CEMS, or COMS was out-of-control, including the information in §63.8(c)(8).
 - (4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.
 - (5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.
 - (6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.
 - (7) A summary of the total duration of CPMS, CEMS, or COMS downtime during the reporting period and the total duration of CPMS, CEMS, or COMS downtime as a percent of the total source operating time during that reporting period.
 - (8) An identification of each air pollutant that was monitored at the affected source.
 - (9) A brief description of the process units.
 - (10) A brief description of the CPMS, CEMS, or COMS.
 - (11) The date of the latest CPMS, CEMS, or COMS certification or audit.
 - (12) A description of any changes in CPMS, CEMS, or COMS, processes, or controls since the last reporting period.
- (e) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 6 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), submission of the compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) If acceptable to both the Administrator and you, you may submit reports and notifications electronically.

[↑ Back to Top](#)

§63.8694 What records must I keep?

(a) You must keep the following records:

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in §63.10(b)(2)(viii).

(b) You must keep the records in §63.6(h)(6) for visible emission observations.

(c) You must keep the records required in Table 5 to this subpart to show continuous compliance with each operating limit that applies to you.

(d) Records of any shared equipment determinations as specified in §63.8682(b).

[↑ Back to Top](#)

§63.8695 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

[↑ Back to Top](#)

Other Requirements and Information

[↑ Back to Top](#)

§63.8696 What parts of the General Provisions apply to me?

Table 7 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

[↑ Back to Top](#)

§63.8697 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. Environmental Protection Agency (U.S. EPA), or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the following authorities are retained by the Administrator of U.S. EPA:

(1) Approval of alternatives to the requirements in §§63.8681, 63.8682, 63.8683, 63.8684(a) through (c), 63.8686, 63.8687, 63.8688, 63.8689, 63.8690, and 63.8691.

(2) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major changes to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

[↑ Back to Top](#)

§63.8698 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in 40 CFR 63.2, the General Provisions of this part, and in this section as follows:

Adhesive applicator means the equipment used to apply adhesive to roofing shingles for producing laminated or dimensional roofing shingles.

Asphalt flux means the organic residual material from distillation of crude oil that is generally used in asphalt roofing manufacturing and paving and non-paving asphalt products.

Asphalt loading rack means the equipment at an asphalt processing facility used to transfer oxidized asphalt from a storage tank into a tank truck, rail car, or barge.

Asphalt processing facility means any facility engaged in the preparation of asphalt flux at stand-alone asphalt processing facilities, petroleum refineries, and asphalt roofing facilities. Asphalt preparation, called “blowing,” is the oxidation of asphalt flux, achieved by bubbling air through the heated asphalt, to raise the softening point and to reduce penetration of the oxidized asphalt. An asphalt processing facility includes one or more asphalt flux blowing stills, asphalt flux storage tanks storing asphalt flux intended for processing in the blowing stills, oxidized asphalt storage tanks, and oxidized asphalt loading racks.

Asphalt roofing manufacturing facility means a facility consisting of one or more asphalt roofing manufacturing lines.

Asphalt roofing manufacturing line means the collection of equipment used to manufacture asphalt roofing products through a series of sequential process steps. The equipment that comprises an asphalt roofing manufacturing line varies depending on the type of substrate used (*i.e.*, organic or inorganic) and the final product manufactured (*e.g.*, roll roofing, laminated shingles). For example, an asphalt roofing manufacturing line that uses fiberglass mat as a substrate typically would not include a saturator/wet looper (or the saturator/wet looper could be bypassed if the line manufacturers multiple types of products). An asphalt roofing manufacturing line can include a saturator (including wet looper), coater, coating mixers, sealant applicators, adhesive applicators, and asphalt storage and process tanks. The number of asphalt roofing manufacturing lines at a particular facility is determined by the number of saturators (or coaters) operated in parallel. For example, an asphalt roofing manufacturing facility with two saturators (or coaters) operating in parallel would be considered to have two separate roofing manufacturing lines.

Asphalt storage tank means any tank used to store asphalt flux, oxidized asphalt, and modified asphalt, at asphalt roofing manufacturing facilities, petroleum refineries, and asphalt processing facilities. Storage tanks containing cutback asphalts (asphalts diluted with solvents to reduce viscosity for low temperature applications) and emulsified asphalts (asphalts dispersed in water with an emulsifying agent) are not subject to this subpart.

Blowing still means the equipment in which air is blown through asphalt flux to change the softening point and penetration rate of the asphalt flux, creating oxidized asphalt.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

Coater means the equipment used to apply amended (filled or modified) asphalt to the top and bottom of the substrate (typically fiberglass mat) used to manufacture shingles and rolled roofing products.

Coating mixer means the equipment used to mix coating asphalt and a mineral stabilizer, prior to applying the stabilized coating asphalt to the substrate.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors.

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 limitation (including any 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 limitation (including any 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.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

Group 1 asphalt loading rack means an asphalt loading rack that loads asphalt with a maximum temperature of 260 °C (500 °F) or greater and has a maximum true vapor pressure of 10.4 kiloPascals (kPa) (1.5 pounds per square inch absolute (psia)) or greater.

Group 2 asphalt loading rack means an asphalt loading rack that is not a Group 1 asphalt loading rack.

Group 1 asphalt storage tank means an asphalt storage tank that meets both of the following criteria:

- (1) Has a capacity of 177 cubic meters (47,000 gallons) of asphalt or greater; and
- (2) Stores asphalt at a maximum temperature of 260 °C (500 °F) or greater and has a maximum true vapor pressure of 10.4 kPa (1.5 psia) or greater.

Group 2 asphalt storage tank means any asphalt storage tank with a capacity of 1.93 megagrams (Mg) of asphalt or greater that is not a Group 1 asphalt storage tank.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section

following the combustion section and the two are joined by ducts or connections carrying flue gas.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored asphalt at its maximum storage temperature.

Modified asphalt means asphalt that has been mixed with polymer modifiers.

Oxidized asphalt means asphalt that has been prepared by passing air through liquid asphalt flux in a blowing still.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Research and development equipment means any equipment whose primary purpose is to conduct research and development to develop new processes and products, where such equipment is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a *de minimis* manner.

Responsible official means responsible official as defined in 40 CFR 70.2.

Saturator means the equipment in which substrate (predominantly organic felt) is filled with asphalt. Saturators are predominantly used for the manufacture of saturated felt products. The term saturator includes the saturator and wet looper.

Sealant applicator means the equipment used to apply a sealant strip to a roofing product. The sealant strip is used to seal overlapping pieces of roofing product after they have been applied.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[68 FR 24577, May 7, 2003, as amended at 70 FR 28364, May 17, 2005]

[↑ Back to Top](#)

Table 1 to Subpart LLLLL of Part 63—Emission Limitations

For—	You must meet the following emission limitation—
1. Each blowing still, Group 1 asphalt loading rack, and Group 1 asphalt storage tank at existing, new, and reconstructed asphalt processing facilities; and each Group 1 asphalt storage tank at existing, new, and reconstructed	a. Reduce total hydrocarbon mass emissions by 95 percent, or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen;

roofing manufacturing lines; and each coating mixer, saturator (including wet looper), coater, sealant applicator, adhesive applicator, and Group 1 asphalt storage tank at new and reconstructed asphalt roofing manufacturing lines	<p>b. Route the emissions to a combustion device achieving a combustion efficiency of 99.5 percent;</p> <p>c. Route the emissions to a combustion device that does not use auxiliary fuel achieving a total hydrocarbon (THC) destruction efficiency of 95.8 percent;</p> <p>d. Route the emissions to a boiler or process heater with a design heat input capacity of 44 megawatts (MW) or greater;</p> <p>e. Introduce the emissions into the flame zone of a boiler or process heater; or</p> <p>f. Route emissions to a flare meeting the requirements of §63.11(b).</p>
2. The total emissions from the coating mixer, saturator (including wet looper), coater, sealant applicator, and adhesive applicator at each existing asphalt roofing manufacturing line. ^a	<p>a. Limit particulate matter emissions to 0.04 kilograms emissions per megagram (kg/Mg) (0.08 pounds per ton, lb/ton) of asphalt shingle or mineral-surfaced roll roofing produced; or</p> <p>b. Limit particulate matter emissions to 0.4 kg/Mg (0.8 lb/ton) of saturated felt or smooth-surfaced roll roofing produced.</p>
3. Each saturator (including wet looper) and coater at existing, new, and reconstructed asphalt roofing manufacturing lines. ^a	<p>a. Limit exhaust gases to 20 percent opacity; and</p> <p>b. Limit visible emissions from the emission capture system to 20 percent of any period of consecutive valid observations totaling 60 minutes.</p>
4. Each Group 2 asphalt storage tank at existing, new, and reconstructed asphalt processing facility and asphalt roofing manufacturing lines. ^a	Limit exhaust gases to 0 percent opacity. ^b

^aAs an alternative to meeting the particulate matter and opacity limits, these emission sources may comply with the THC percent reduction or combustion efficiency standards.

^bThe opacity limit can be exceeded for on consecutive 15-minute period in any 24-hour period when the storage tank transfer lines are being cleared. During this 15-minute period, the control device must not be bypassed. If the emissions from the asphalt storage tank are ducted to the

saturator control device, the combined emissions from the saturator and storage tank must meet the 20 percent opacity limit (specified in 4.a of table 1) during this 15-minute period. At any other time, the opacity limit applies to Group 2 asphalt storage tanks.

[↑ Back to Top](#)

Table 2 to Subpart LLLLL of Part 63—Operating Limits

For—	You must ^a
1. Non-flare combustion devices with a design heat input capacity less than 44 MW or where the emissions are not introduced into the flame zone	Maintain the 3-hour average ^b combustion zone temperature at or above the operating limit established during the performance test.
2. Flares	Meet the operating requirements specified in §63.11(b).
3. Control devices used to comply with the particulate matter standards.	a. Maintain the 3-hour average ^b inlet gas temperature at or below the operating limit established during the performance test; and b. Maintain the 3-hour average ^b pressure drop across the device ^c at or below the operating limit established during the performance test.
4. Control devices other than combustion devices or devices used to comply with the particulate matter emission standards	Maintain the approved monitoring parameters within the operating limits established during the performance test.

^aThe operating limits specified in Table 2 are applicable if you are monitoring control device operating parameters to demonstrate continuous compliance. If you are using a CEMS or COMS, you must maintain emissions below the value established during the initial performance test.

^bA 15-minute averaging period can be used as an alternative to the 3-hour averaging period for this parameter.

^cAs an alternative to monitoring the pressure drop across the control device, owners or operators using an ESP to achieve compliance with the emission limits specified in Table 1 of this subpart can monitor the voltage to the ESP. If this option is selected, the ESP voltage must be maintained at or above the operating limit established during the performance test.

[↑ Back to Top](#)

Table 3 to Subpart LLLLL of Part 63—Requirements for Performance Tests^a b

For—	You must—	Using—	According to the following
------	-----------	--------	----------------------------

			requirements—
1. All particulate matter, total hydrocarbon, carbon monoxide, and carbon dioxide emission tests	a. Select sampling port's location and the number of traverse points	i. EPA test method 1 or 1A in appendix A to part 60 of this chapter	A. For demonstrating compliance with the total hydrocarbon percent reduction standard, the sampling sites must be located at the inlet and outlet of the control device and prior to any releases to the atmosphere. B. For demonstrating compliance with the particulate matter mass emission rate, THC destruction efficiency, THC outlet concentration, or combustion efficiency standards, the sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.
2. All particulate matter and total hydrocarbon tests	Determine velocity and volumetric flow rate	EPA test method 2, 2A, 2C, 2D, 2F, or 2G, as appropriate, in appendix A to part 60 of this chapter	
3. All particulate matter and total hydrocarbon tests	Determine the gas molecular weight used for flow rate determination	EPA test method 3, 3A, 3B, as appropriate, in appendix A to part 60 of this chapter	
4. All particulate matter, total hydrocarbon, carbon monoxide, and carbon dioxide emission tests	Measure moisture content of the stack gas	EPA test method 4 in appendix A to part 60 of this chapter	
5. All particulate matter emission tests	Measure the asphalt processing rate or the asphalt roofing manufacturing rate and the asphalt content of the product manufactured, as appropriate		

6. Each control device used to comply with the particulate matter emission standards	Measure the concentration of particulate matter	EPA test method 5A in appendix A to part 60 of this chapter	For demonstrating compliance with the particulate matter standard, the performance tests must be conducted under normal operating conditions and while manufacturing the roofing product that is expected to result in the greatest amount of hazardous air pollutant emissions.
7. All opacity tests	Conduct opacity observations	EPA test method 9 in appendix A to part 60 of this chapter	Conduct opacity observations for at least 3 hours and obtain 30, 6-minute averages.
8. All visible emission tests	Conduct visible emission observations	EPA test method 22 in appendix A to part 60 of this chapter	Modify EPA test method 22 such that readings are recorded every 15 seconds for a period of consecutive observations totaling 60 minutes.
9. Each combustion device used to comply with the combustion efficiency or THC standards	a. Measure the concentration of carbon dioxide b. Measure the concentration of carbon monoxide	EPA test method 3A in appendix A to part 60 of this chapter EPA test method 10 in appendix A to part 60 of this chapter	
	c. Measure the concentration of total hydrocarbons	EPA test method 25A in appendix A to part 60 of this chapter	
10. Each control device used to comply with the THC reduction efficiency or outlet concentration standards	Measure the concentration of total hydrocarbons	EPA test method 25A in appendix A to part 60 of this chapter	
11. Each combustion device	Establish a site-specific combustion zone temperature limit	Data from the CPMS and the applicable performance test method(s)	You must collect combustion zone temperature data every 15 minutes during the entire period of the initial 3-hour performance test, and determine the average combustion zone temperature over the 3-hour performance test

			by computing the average of all of the 15-minute readings.
12. Each control device used to comply with the particulate matter emission standards	Establish a site-specific inlet gas temperature limit; and establish a site-specific limit for the pressure drop across the device	Data from the CPMS and the applicable performance test method(s)	You must collect the inlet gas temperature and pressure drop ^b data every 15 minutes during the entire period of the initial 3-hour performance test, and determine the average inlet gas temperature and pressure drop ^c over the 3-hour performance test by computing the average of all of the 15-minute readings.
13. Each control device other than a combustion device or device used to comply with the particulate matter emission standards	Establish site-specific monitoring parameters	Process data and data from the CPMS and the applicable performance test method(s)	You must collect monitoring parameter data every 15 minutes during the entire period of the initial 3-hour performance test, and determine the average monitoring parameter values over the 3-hour performance test by computing the average of all of the 15-minute readings.
14. Each flare used to comply with the THC percent reduction or PM emission limits	Assure that the flare is operated and maintained in conformance with its design	The requirements of §63.11(b)	

^aAs specified in §63.8687(e), you may request that data from a previously-conducted emission test serve as documentation of conformance with the emission standards and operating limits of this subpart.

^bPerformance tests are not required if: (1) The emissions are routed to a boiler or process heater with a design heat input capacity of 44 MW or greater; or (2) the emissions are introduced into the flame zone of a boiler or process heater.

^cAs an alternative to monitoring the pressure drop across the control device, owners or operators using an ESP to achieve compliance with the emission limits specified in Table 1 of this subpart can monitor the voltage to the ESP.

[↑ Back to Top](#)

Table 4 to Subpart LLLLL of Part 63—Initial Compliance With Emission Limitations

For—	For the following emission limitation—	You have demonstrated initial compliance if—
1. Each blowing still, Group 1 asphalt loading rack, and Group 1 asphalt storage tank, at existing, new, and reconstructed asphalt processing facilities	a. Reduce total hydrocarbon mass emissions by 95 percent or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen	i. The total hydrocarbon emissions, determined using the equations in §63.8687 and the test methods and procedures in Table 3 to this subpart, over the period of the performance test are reduced by at least 95 percent by weight or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen; and ii. You have a record of the average control device operating parameters ^a over the performance test during which emissions were reduced according to 1.a.i. of this table.
	b. Route the emissions to a combustion device achieving a combustion efficiency of 99.5 percent	i. The combustion efficiency of the combustion device, determined using the equations in §63.8687 and the test methods and procedures in Table 3 to this subpart, over the period of the performance test is at least 99.5 percent; and ii. You have a record of the average combustion zone temperature ^a and carbon monoxide, carbon dioxide, and total hydrocarbon outlet concentrations over the performance test during which the combustion efficiency was at least 99.5 percent.
	c. Route the emissions to a combustion device that does not use auxiliary fuel achieving a THC destruction efficiency of 95.8 percent	i. The THC destruction efficiency of the combustion device, determined using the equations in §63.8687 and the test methods and procedures in Table 3 to this subpart, over the period of the performance test is at least 95.8 percent; and ii. You have a record of the average combustion zone temperature ^a and carbon monoxide, carbon dioxide, and total hydrocarbon outlet concentrations over the performance test during which the THC destruction efficiency was at least 95.8 percent.
	d. Route emissions to a	You have a record of the boiler or

	boiler or process heater with a design heat input capacity of 44 MW or greater	process heater design heat capacity.
	e. Introduce the emissions into the flame zone of a boiler or process heater	You have a record that shows the emissions are being introduced into the boiler or process heater flame zone.
	f. Route emissions to a flare meeting the requirements of §63.11(b)	You have a record of the flare design and operating requirements.
2. Each coating mixer, saturator (including wet looper), coater, sealant applicator, adhesive applicator, and Group 1 asphalt storage tank at new and reconstructed asphalt roofing manufacturing lines	a. Reduce total hydrocarbon mass emissions by 95 percent or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen	See 1.a.i. and ii. of this table.
	b. Route the emissions to a combustion device achieving a combustion efficiency of 99.5 percent	See 1.b.i. and ii. of this table.
	c. Route the emissions to a combustion device that does not use auxiliary fuel achieving a THC destruction efficiency of 95.8 percent	See 1.c.i. and ii. of this table.
	d. Route emissions to a boiler or process heater with a design heat input capacity of 44 MW or greater	See 1.d. of this table.
	e. Introduce the emissions into the flame zone of a boiler or process heater	See 1.e. of this table.
	f. Route emissions to a flare meeting the requirements of	See 1.f. of this table.

	§63.11(b)	
3. The total emissions from the coating mixer, saturator (including wet looper), coater, sealant applicator, and adhesive applicator at each existing asphalt roofing manufacturing line	a. Limit PM emissions to 0.04 kg/Mg (0.08 lb/ton) of asphalt shingle or mineral-surfaced roll roofing produced	i. The PM emissions, determined using the equations in §63.8687 and the test methods and procedures in Table 3 to this subpart, over the period of the performance test are no greater than the applicable emission limitation; and ii. You have a record of the average control device ^a or process parameters over the performance test during which the particulate matter emissions were no greater than the applicable emission limitation.
	b. Limit PM emissions to 0.4 kg/Mg (0.8 lb/ton) of saturated felt or smooth-surfaced roll roofing produced	See 3.a.i. and ii. of this table.
4. Each saturator (including wet looper) and coater at an existing, new, or reconstructed asphalt roofing manufacturing line	a. Limit visible emissions from the emissions capture system to 20 percent of any period of consecutive valid observations totaling 60 minutes	The visible emissions, measured using EPA test method 22, for any period of consecutive valid observations totaling 60 minutes during the initial compliance period described in §63.8686(b) do not exceed 20 percent.
	b. Limit opacity emissions to 20 percent	The opacity, measured using EPA test method 9, for each of the first 30 6-minute averages during the initial compliance period described in §63.8686(b) does not exceed 20 percent.
5. Each Group 2 asphalt storage tank at existing, new, and reconstructed asphalt processing facilities and asphalt roofing manufacturing lines	Limit exhaust gases to 0 percent opacity	The opacity, measured using EPA test method 9, for each of the first 30 6-minute averages during the initial compliance period described in §63.8686(b) does not exceed 0 percent.

^aIf you use a CEMS or COMS to demonstrate compliance with the emission limits, you are not required to record control device operating parameters.

[↑ Back to Top](#)

Table 5 to Subpart LLLLL of Part 63—Continuous Compliance With Operating Limits^a

For—	For the following operating limit—	You must demonstrate continuous compliance by—
1. Each non-flare combustion device. ^b	a. Maintain the 3-hour ^c average combustion zone temperature at or above the operating limit establishing during the performance test	i. Passing the emissions through the control device; and ii. Collecting the combustion zone temperature data according to §63.8688(b); and iii. Reducing combustion zone temperature data to 3-hour ^c averages according to calculations in Table 3 to this subpart; and iv. Maintaining the 3-hour ^c average combustion zone temperature within the level established during the performance test.
2. Each flare	Meet the operating requirements specified in §63.11(b)	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.
3. Control devices used to comply with the particulate matter emission standards	a. Maintain the 3-hour ^c average inlet gas temperature and pressure drop across device ^d at or below the operating limits established during the performance test	i. Passing the emissions through the control device; and ii. Collecting the inlet gas temperature and pressure drop ^d data according to §63.8688 (b) and (c); and iii. Reducing inlet gas temperature and pressure drop ^d data to 3-hour ^c averages according to calculations in Table 3 to this subpart; and iv. Maintaining the 3-hour ^c average inlet gas temperature and pressure drop ^d within the level established during the performance test.
4. Control devices other than combustion devices or devices used to comply	a. Maintain the monitoring parameters within the operating limits established during the	i. Passing the emissions through the devices; ii. Collecting the monitoring

with the particulate matter emission	performance test	parameter data according to §63.8688(d); and iii. Reducing the monitoring parameter data to 3-hour ^c averages according to calculations in Table 3 to this subpart; and iv. Maintaining the monitoring parameters within the level established during the performance test.
--------------------------------------	------------------	--

^aThe operating limits specified in Table 2 and the requirements specified in Table 5 are applicable if you are monitoring control device operating parameters to demonstrate continuous compliance. If you use a CEMS or COMS to demonstrate compliance with the emission limits, you are not required to record control device operating parameters. However, you must maintain emissions below the value established during the initial performance test. Data from the CEMS and COMS must be reduced as specified in §63.8(g).

^bContinuous parameter monitoring is not required if (1) the emissions are routed to a boiler or process heater with a design heat input capacity of 44 MW or greater; or (2) the emissions are introduced into the flame zone of a boiler or process heater.

^cA 15-minute averaging period can be used as an alternative to the 3-hour averaging period for this parameter.

^dAs an alternative to monitoring the pressure drop across the control device, owners or operators using an ESP to achieve compliance with the emission limits specified in Table 1 of this subpart can monitor the voltage to the ESP. If this option is selected, the ESP voltage must be maintained at or above the operating limit established during the performance test.

[68 FR 24577, May 7, 2003, as amended at 70 FR 28365, May 17, 2005]

[↑ Back to Top](#)

Table 6 to Subpart LLLLL of Part 63—Requirements for Reports

You must submit—	The report must contain—	You must submit the report—
1. An initial notification	The information in §63.9(b)	According to the requirements in §63.9(b).
2. A notification of performance test	A written notification of the intent to conduct a performance test	At least 60 calendar days before the performance test is

		scheduled to begin, as required in §63.9(e).
3. A notification of opacity and visible emission observations	A written notification of the intent to conduct opacity and visible emission observations	According to the requirements in §63.9(f).
4. Notification of compliance status	The information in §63.9(h)(2) through (5), as applicable	According to the requirements in §63.9(h)(2) through (5), as applicable.
5. A compliance report	a. A statement that there were no deviations from the emission limitations during the reporting period, if there are no deviations from any emission limitations (emission limit, operating limit, opacity limit, and visible emission limit) that apply to you	Semiannually according to the requirements in §63.8693(b).
	b. If there were no periods during which the CPMS, CEMS, or COMS was out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CPMS, CEMS, or COMS was out-of-control during the reporting period	Semiannually according to the requirements in §63.8693(b).
	c. If you have a deviation from any emission limitation (emission limit, operating limit, opacity limit, and visible emission limit), the report must contain the information in §63.8693(c). If there were periods during which the CPMS, CEMS, or COMS was out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.8693(d)	Semiannually according to the requirements in §63.8693(b).
	d. If you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.8693(b).
6. An immediate startup, shutdown, and malfunction report if you have a startup,	The information in §63.10(d)(5)(ii)	By fax or telephone within 2 working days after starting actions inconsistent with the

shutdown, or malfunction during the reporting period and actions taken were not consistent with your startup, shutdown, and malfunction plan		plan followed by a letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.
--	--	---

[↑ Back to Top](#)

Table 7 to Subpart LLLLL of Part 63—Applicability of General Provisions to Subpart LLLLL

Citation	Subject	Brief description	Applies to subpart LLLLL
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications	Yes.
§63.2	Definitions	Definitions for part 63 standards	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension GP apply to area sources that become major	Yes.
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for section 112(f)	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal	Yes.
§63.6(b)(6)	[Reserved]		

§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source	Yes.
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	1. Comply according to date in subpart, which must be no later than 3 years after effective date 2. For section 112(f) standards, comply within 90 days of effective date unless compliance extension has been granted	Yes.
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years)	Yes.
§63.6(d)	[Reserved]		
§63.6(e)(1)	Operation & Maintenance	1. Operate to minimize emissions at all times 2. Correct malfunctions as soon as practicable 3. Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met	Yes.
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	Startup, Shutdown, and Malfunction (SSM) Plan (SSMP)	1. Requirement for SSM and startup, shutdown, malfunction plan 2. Content of SSMP	Yes.
§63.6(f)(1)	Compliance Except During SSM	You must comply with emission standards at all times except during SSM	Yes.
§63.6(f)(2)-(3)	Methods for Determining	Compliance based on	Yes.

	Compliance	performance test, operation and maintenance plans, records, inspection	
§63.6(g)(1)-(3)	Alternative Nonopacity Standard	Procedures for getting an alternative nonopacity standard	Yes.
§63.6(h)	Opacity/Visible Emission (VE) Standards	Requirements for opacity and VE limits	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards	You must comply with opacity/VE emission limitations at all times except during SSM	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	If standard does not state test method, use EPA test method 9, 40 CFR 60, appendix A for opacity and EPA test method 22, 40 CFR 60, appendix A for VE	No. The test methods for opacity and visible emissions are specified in §63.8687.
§63.6(h)(2)(ii)	[Reserved]		
§63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this rule	Yes.
§63.6(h)(3)	[Reserved]		
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Must notify Administrator of anticipated date of observation	Yes.
§63.6(h)(5)(i), (iii)-(v)	Conducting Opacity/VE Observations	Dates and Schedule for conducting opacity/VE observations	Yes.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times	Must have at least 3 hours of observation with thirty 6-minute averages	Yes.
§63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Must keep records available and allow Administrator to inspect	Yes.
§63.6(h)(7)(i)	Report COMS Monitoring Data from Performance Test	Must submit COMS data with other performance test data	Yes, if COMS used.
§63.6(h)(7)(ii)	Using COMS instead of EPA test method 9, 40 CFR 60, appendix A	Can submit COMS data instead of EPA test method 9, 40 CFR 60, appendix A results even if rule requires	Yes, if COMS used.

		EPA test method 9, 40 CFR 60, appendix A, but must notify Administrator before performance test	
§63.6(h)(7)(iii)	Averaging time for COMS during performance test	To determine compliance, must reduce COMS data to 6-minute averages	Yes, if COMS used.
§63.6(h)(7)(iv)	COMS requirements	Owner/operator must demonstrate that COMS performance evaluations are conducted according to §63.8(e), COMS are properly maintained and operated according to §63.8(c) and data quality as §63.8(d)	Yes, if COMS used.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards	COMS is probative but not conclusive evidence of compliance with opacity standard, even if EPA test method 9, 40 CFR 60, appendix A observation shows otherwise. Requirements for COMS to be probative evidence, proper maintenance, meeting PS 1, and data have not been altered	Yes, if COMS used.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Administrator will use all COMS, EPA test method 9, 40 CFR 60, appendix A, and EPA test method 22, 40 CFR 60, appendix A results, as well as information about operation and maintenance to determine compliance	Yes.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard	Yes.
§63.6(i)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension	Yes.
§63.6(j)	Presidential Compliance Exemption	President may exempt source category from requirement to comply with rule	Yes.
§63.7(a)(1)-(2)	Performance Test Dates	Dates for conducting initial	Yes.

		performance testing and other compliance demonstrations. Must conduct 180 days after first subject to rule	
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA section 114 at any time	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test	Yes.
§63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date	Yes.
§63.7(c)	Quality Assurance/Test Plan	1. Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: 2. Test plan approval procedures 3. Performance audit requirements 4. Internal and external QA procedures for testing	Yes.
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.
§63.7(e)(1)	Conditions for Conducting Performance Tests	1. Performance tests must be conducted under representative conditions. Cannot conduct performance tests during SSM 2. Not a violation to exceed standard during SSM	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests	Must conduct according to rule and EPA test methods unless Administrator approves alternative	Yes.
§63.7(e)(3)	Test Run Duration	1. Must have three test runs of at least 1 hour each 2. Compliance is based on arithmetic mean of three runs 3. Conditions when data from an additional test run can be used	Yes.

§63.7(f)	Alternative Test Method	Procedures by which Administrator can grant approval to use an alternative test method	Yes.
§63.7(g)	Performance Test Data Analysis	1. Must include raw data in performance test report 2. Must submit performance test data 60 days after end of test with the Notification of Compliance Status 3. Keep data for 5 years	Yes.
§63.7(h)	Waiver of Tests	Procedures for Administrator to waive performance test	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements	Subject to all monitoring requirements in standard	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply	Yes, if CEMS used.
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring with Flares	Unless your rule says otherwise, the requirements for flares in §63.11 apply	Yes.
§63.8(b)(1)	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative	Yes.
§63.8(b) (2)-(3)	Multiple Effluents and Multiple Monitoring Systems	1. Specific requirements for installing monitoring systems 2. Must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise 3. If more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Maintain monitoring system in a manner consistent with good air pollution control practices	Yes.

§63.8(c)(1)(i)	Routine and predictable CMS malfunction	1. Keep parts for routine repairs readily available 2. Reporting requirements for CMS malfunction when action is described in SSM plan	Yes.
§63.8(c)(1)(ii)	CMS malfunction not in SSP plan	Reporting requirements for CMS malfunction when action is not described in SSM plan	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements	1. How Administrator determines if source complying with operation and maintenance requirements 2. Review of source O&M procedures, records, manufacturer's instructions, recommendations, and inspection of monitoring system	Yes.
§63.8(c)(2)-(3)	Monitoring System Installation	1. Must install to get representative emission and parameter measurements 2. Must verify operational status before or at performance test	Yes.
§63.8(c)(4)	CMS Requirements	CMS must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts	No; §63.8690 specifies the CMS requirements.
§63.8(c)(4)(i)-(ii)	CMS Requirements	1. COMS must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period 2. CEMS must have a minimum of one cycle of operation for each successive 15-minute period	Yes, if COMS used.
§63.8(c)(5)	COMS Minimum Procedures	COMS minimum procedures	Yes.
§63.8(c)(6)	CMS Requirements	Zero and High level	No; §63.8688

		calibration check requirements	specifies the CMS requirements.
§63.8(c)(7)-(8)	CMS Requirements	Out-of-control periods, including reporting	Yes.
§63.8(d)	CMS Quality Control	1. Requirements for CMS quality control, including calibration, etc 2. Must keep quality control plan on record for the life of the affected source 3. Keep old versions for 5 years after revisions	No; §63.8688 specifies the CMS requirements.
§63.8(e)	CMS Performance Evaluation	Notification, performance evaluation test plan, reports	No; §63.8688 specifies the CMS requirements.
§63.8(f)(1)-(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring	Yes.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for CEMS	Yes, if CEMS used.
§63.8(g)(1)-(4)	Data Reduction	1. COMS 6-minute averages calculated over at least 36 evenly spaced data points 2. CEMS 1-hour averages computed over at least 4 equally spaced data points	Yes, if CEMS or COMS used.
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for CMS	No; §63.8690 specifies the CMS requirements.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§63.9(b)(1)-(5)	Initial Notifications	1. Submit notification 120 days after effective date 2. Notification of intent to construct/reconstruct; notification of commencement of construct/reconstruct; notification of startup 3. Contents of each	Yes.

§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed Best Achievable Control Technology (BACT)/Lowest Achievable Emission Rate (LAER)	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date	Yes.
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	Yes.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	Yes.
§63.9(g)	Additional Notifications When Using CMS	1. Notification of performance evaluation 2. Notification using COMS data 3. Notification that the criterion for use of alternative to relative accuracy testing was exceeded	No; §63.8692 specifies the CMS notification requirements.
§63.9(h)(1)-(6)	Notification of Compliance Status	1. Contents. 2. Due 60 days after end of performance test or other compliance demonstration, except for opacity/VE, which are due 30 days after 3. When to submit to Federal vs. State authority	Yes.
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in dates when notifications must be submitted	Yes.
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change	Yes.
§63.10(a)	Recordkeeping/Reporting	1. Applies to all, unless compliance extension 2. When to submit to Federal vs. State authority 3. Procedures for owners of more than 1 source	Yes.
§63.10(b)(1)	Recordkeeping/Reporting	1. General Requirements	Yes.

		2. Keep all records readily available. 3. Keep for 5 years	
§63.10(b)(2)(i)-(v)	Records related to Startup, Shutdown, and Malfunction	1. Occurrence of each of operation (process equipment) 2. Occurrence of each malfunction of air pollution equipment 3. Maintenance on air pollution control equipment 4. Actions during startup, shutdown, and malfunction	Yes.
§63.10(b)(2)(vi) and (x-xi)	CMS Records	1. Malfunctions, inoperative, out-of-control 2. Calibration checks 3. Adjustments, maintenance	Yes.
§63.10(b)(2)(vii)-(ix)	Records	1. Measurements to demonstrate compliance with emission limitations 2. Performance test, performance evaluation, and visible emission observation results 3. Measurements to determine conditions of performance tests and performance evaluations	Yes.
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test	Yes.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status	Yes.
§63.10(b)(3)	Records	Applicability determinations	Yes.
§63.10(c)(1)-(6), (9)-(15)	Records	Additional records for CMS	No; §63.8694 specifies the CMS recordkeeping requirements.
§63.10(c)(7)-(8)	Records	Records of excess emissions and parameter monitoring	No; §63.8694 specifies the

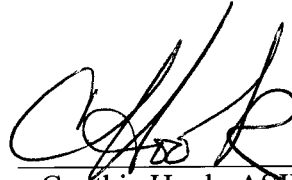
		exceedances for CMS	CMS recordkeeping requirements.
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes.
§63.10(d)(2)	Report of Performance Test Results	When to submit to Federal or State authority	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports	Contents and submission	Yes.
§63.10(e)(1), (2)	Additional CMS Reports	1. Must report results for each CEM on a unit 2. Written copy of performance evaluation 3. Three copies of COMS performance evaluation	Yes.
§63.10(e)(3)	Reports	Excess emission reports	No; §63.8693 specifies the reporting requirements.
§63.10(e)(3)(i)-(iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedances (now defined as deviations)	No; §63.8693 specifies the reporting requirements.
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	1. Requirement to revert to the frequency specified in the relevant standard if there is an excess emissions and parameter monitor exceedances (now defined as deviations) 2. Provision to request semiannual reporting after compliance for one year 3. Submit report by 30th day following end of quarter or calendar half 4. If there has not been an exceedance or excess emission (now defined as	No; §63.8693 specifies the reporting requirements.

		deviations), report content is a statement that there have been no deviations	
§63.10(e)(3)(iv)-(v)	Excess Emissions Reports	Must submit report containing all of the information in §63.10(c)(5)(13), §63.8(c)(7)-(8)	No; §63.8693 specifies the reporting requirements.
§63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	1. Requirements for reporting excess emissions for CMS (now called deviations) 2. Requires all of the information in §63.10(c)(5)(13), §63.8(c)(7)-(8)	No; §63.8693 specifies the reporting requirements.
§63.10(e)(4)	Reporting COMS data	Must submit COMS data with performance test data	Yes, if COMS used.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11	Flares	Requirements for flares	Yes.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent	Yes.
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential information	Yes.

[68 FR 24577, May 7, 2003, as amended at 71 FR 20469, Apr. 20, 2006]

CERTIFICATE OF SERVICE

I, Cynthia Hook , hereby certify that a copy of this permit has been mailed by first class mail to
Lion Oil Company, 1000 McHenry Drive, El Dorado, AR, 71730, on this 31st day of
August, 2016.

A handwritten signature in black ink, appearing to read 'C. Hook', written over a horizontal line.

Cynthia Hook, ASIII, Air Division