NOTICE OF 30-DAY PERIOD
FOR PUBLIC COMMENT

Preliminary Findings Regarding the Renewal of a
Part 70 Administrative Operating Permit

for CountryMark Refining and Logistics, LLC in Posey County

Part 70 Administrative Operating Permit Renewal No.: T129-41688-00037

The Indiana Department of Environmental Management (IDEM) has received an application from CountryMark Refining and Logistics, LLC located at South Mann and West Ohio Street, Mount Vernon, Indiana 47620 for a renewal of its Part 70 Administrative Operating Permit issued on April 21, 2015. If approved by IDEM’s Office of Air Quality (OAQ), this proposed renewal would allow CountryMark Refining and Logistics, LLC to continue to operate its existing source.

This draft permit does not contain any new equipment that would emit air pollutants; however, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g., changes that add or modify synthetic minor emission limits). This notice fulfills the public notice procedures to which those conditions are subject. IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow for these changes.

A copy of the permit application and IDEM's preliminary findings are available at:

Alexandrian Public Library
115 W 5th St.
Mount Vernon, IN 47620

and

IDEM Southwest Regional Office
114 South 7th Street
P.O. Box 128
Petersburg, IN 47567-0128

A copy of the preliminary findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

A copy of the preliminary findings is also available via IDEM’s Virtual File Cabinet (VFC.) Please go to: http://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

How can you participate in this process?

The date that this notice is posted on IDEM’s website (https://www.in.gov/idem/5474.htm) marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the air pollution impact of this draft permit are received, with a request for a public hearing,
IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM’s mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number T-129-41688-00037 in all correspondence.

Comments should be sent to:

Michaela Hecox
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 GCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for Michaela Hecox or (317) 233-3130
Or dial directly: (317) 233-3130
Fax: (317) 232-6749 attn: Michaela Hecox
E-mail: mhecox@idem.in.gov

All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor, or noise. For such issues, please contact your local officials.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2366.htm; and the Citizens’ Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM’s response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM’s decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, IDEM Southwest Regional Office, and the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251.

If you have any questions, please contact Michaela Hecox of my staff at the above address.

[Signature]
Brian Williams, Section Chief
Permits Branch
Office of Air Quality
Part 70 Administrative Operating Permit Renewal
OFFICE OF AIR QUALITY

CountryMark Refining and Logistics, LLC
South Mann and West Ohio Street
Mount Vernon, Indiana 47620

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

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Issued by:
Brian Williams, Section Chief
Permits Branch
Office of Air Quality

Issuance Date:

Expiration Date:
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Attachment A - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) [40 CFR 63, Subpart R]
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SECTION A  SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary petroleum refinery marine vessel loading and unloading dock.

| Source Address: | South Mann and West Ohio Street, Mount Vernon, Indiana 47620 |
| General Source Phone Number: | (812) 383-8543 |
| SIC Code: | 2911 (Petroleum Refining) 5171 (Petroleum Bulk Stations and Terminals) |
| County Location: | Posey |
| Source Location Status: | Attainment for all criteria pollutants |
| Source Status: | Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories |

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This source definition for this source is incorporated into this permit as follows:

This petroleum refinery and marine vessel loading and unloading river dock terminal consists of two (2) plants:

(a) Plant 1 is located at 1200 Refinery Road, Mount Vernon, IN 47620; and
(b) Plant 2 is located at South Mann St. and West Ohio St., Mount Vernon, IN 47620.

However, these plants are located on one or more adjacent properties, have the same two digit SIC code and a support relationship, and are still under common ownership, therefore they are considered one (1) major source, as defined by 326 IAC 2-7-1(22).

A Part 70 Operating permits will be issued to Country Mark Refining and Logistics, LLC (129-00003). A separate Administrative Part 70 permit will be issued to Country Mark Refining and Logistics, LLC (129-00037), solely for administrative purposes. This conclusion was initially determined under Significant Permit Modification (129-17940-00003) issued on November 24, 2003.

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas. Under 40 CFR 63, Subpart R this is an affected facility. Under 40 CFR 63, Subpart CC this is an affected facility.
A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

(1) For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
(2) For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
(3) For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
(4) For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.
(5) For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.
(6) For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

(A) One (1) fixed roof cone tank, identified as Tank No. 23, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]
(B) One (1) fixed roof cone tank, identified as Tank No. 27, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]
(C) One (1) fixed roof cone tank, identified as Tank No. 28, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]
(D) One (1) fixed roof cone tank, identified as Tank No. 31, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]
(E) One (1) fixed roof cone tank, identified as Tank No. 32, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]
(F) One (1) tank, identified as Skid Tank, constructed in 1960, with a capacity of 576 gallons. [40 CFR 63, Subpart CC]
(G) One (1) tank, identified as Dock Tank, constructed in 1950, with a capacity of 564 gallons. [40 CFR 63, Subpart CC]
(H) One (1) upstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]
(I) One (1) downstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]
J. Pipeline Valves: Gas Stream. [40 CFR 63, Subpart CC]
K. Pipeline Valves: Light Liquid. [40 CFR 63, Subpart CC]
L. Pipeline Valves: Heavy Liquid. [40 CFR 63, Subpart CC]
M. Open Ended Valves. [40 CFR 63, Subpart CC]
N. Flanges. [40 CFR 63, Subpart CC]
O. Pump Seals: Light Liquid. [40 CFR 63, Subpart CC]
P. Pump Seals: Heavy Liquid. [40 CFR 63, Subpart CC]
Q. Drains. [40 CFR 63, Subpart CC]
R. Vessel relief valves. [40 CFR 63, Subpart CC]

A.5 Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]
This stationary source also includes the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Three (3) silos with polyester bag filters, installed in the late 1950’s, containing lime, soda ash, and ferric sulfate used to process water for the plant.
(b) One (1) river water treatment operation, installed in the late 1950’s. This operation removes material from the river water so the water may be used in refinery processes.
(c) One (1) dry storage and handling operation, installed in the late 1950’s, handling limestone, sand, river silt, and similar materials associated with the river water treatment operation.
(d) One (1) aboveground storage tank, Tank 280W, holding hydrostatic test water.
(e) Unpaved roads

A.6 Part 70 Permit Applicability [326 IAC 2-7-2]
This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);
(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).
(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);
SECTION B  GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-7-5(5)]

(a) This permit, T129-41688-00037, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-3-6(a). Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7][IC 13-17-12]

Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.
B.8 Certification \[326 \text{ IAC 2-7-4(f)}\][326 \text{ IAC 2-7-6(1)}][326 \text{ IAC 2-7-5(3)(C)}]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.9 Annual Compliance Certification \[326 \text{ IAC 2-7-6(5)}\]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and
(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance
causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Southwest Regional Office within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

   Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
   Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
   Facsimile Number: 317-233-6865
   Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304.

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;
(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable
requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

1. The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;
2. The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;
3. The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and
4. The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T129-41688-00037 and issued pursuant to permitting programs approved into the state implementation plan have been either:

1. incorporated as originally stated,
2. revised under 326 IAC 2-7-10.5, or
3. deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

B.14 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).
B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination
[326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the
document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source’s failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;
(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;
(2) The date on which the change will occur;
(3) Any change in emissions; and
(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).
(c) Emission Trades [326 IAC 2-7-20(c)]  
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]  
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(b). No prior notification of IDEM, OAQ or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of SO2 or NOX under 326 IAC 21.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]  
A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]  
Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]  
(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:
Indiana Department of Environmental Management  
Permit Administration and Support Section, Office of Air Quality  
100 North Senate Avenue  
MC 61-53 IGCN 1003  
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19][326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Advanced Source Modification Approval [326 IAC 2-7-5(15)][326 IAC 2-7-10.5]

(a) The requirements to obtain a source modification approval under 326 IAC 2-7-10.5 or a permit modification under 326 IAC 2-7-12 are satisfied by this permit for the proposed emission units, control equipment or insignificant activities in Sections A.2 and A.3.

(b) Pursuant to 326 IAC 2-1.1-9 any permit authorizing construction may be revoked if construction of the emission unit has not commenced within eighteen (18) months from the date of issuance of the permit, or if during the construction, work is suspended for a continuous period of one (1) year or more.

B.25 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314][326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.
SECTION C  SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards  [326 IAC 2-7-5(1)]

C.1  Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2  Opacity  [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a)  Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b)  Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.3  Open Burning  [326 IAC 4-1][IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.4  Incineration  [326 IAC 4-2][326 IAC 9-1-2]

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.5  Fugitive Dust Emissions  [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.6  Stack Height  [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.7  Asbestos Abatement Projects  [326 IAC 14-10][326 IAC 18][40 CFR 61, Subpart M]

(a)  Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of
326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

   (A) Asbestos removal or demolition start date;

   (B) Removal or demolition contractor; or

   (C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3.

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3.

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.
Testing Requirements [326 IAC 2-7-6(1)]

C.8 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

(a) For new units:

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

(b) For existing units:

Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance to begin such monitoring. If, due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.11 Instrument Specifications [326 IAC 2-1.1-11][326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]

C.12 Emergency Reduction Plans [326 IAC 1-5-2][326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.13 Risk Management Plan [326 IAC 2-7-5(11)][40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.14 Response to Excursions or Exceedances [326 IAC 2-7-5][326 IAC 2-7-6]

Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system);
any necessary follow-up actions to return operation to normal or usual manner of operation.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;
(2) review of operation and maintenance procedures and records; and/or
(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall record the reasonable response steps taken.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) (“Regulated pollutant, which is used only for purposes of Section 19 of this rule”) from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.17 General Record Keeping Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-6][326 IAC 2-2][326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:
   (AA) All calibration and maintenance records.
   (BB) All original strip chart recordings for continuous monitoring instrumentation.
   (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:
   (AA) The date, place, as defined in this permit, and time of sampling or measurements.
   (BB) The dates analyses were performed.
   (CC) The company or entity that performed the analyses.
   (DD) The analytical techniques or methods used.
   (EE) The results of such analyses.
   (FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:
   (A) A description of the project.
   (B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.
(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)][326 IAC 2-1.1-11][326 IAC 2-2][326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B -Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.
Stratospheric Ozone Protection

C.19 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.
SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas. Under 40 CFR 63, Subpart R this is an affected facility. Under 40 CFR 63, Subpart CC this is an affected facility.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1 Volatile Organic Compounds (VOC) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2019 Modification permitted under MSM 129-41173-00037, the Permittee shall comply with the following:

(a) Prior to completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003):

(1) The throughput of gasoline to the barge loading and unloading facility (Plt ID: 129-00037) shall be less than 83,891,000 equivalent gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) For the purposes of determining compliance, every gallon of crude oil to the barge loading and unloading facility shall be equivalent to 0.256 gallons of gasoline based on VOC emissions, such that the total gallons of gasoline and gasoline equivalent input does not exceed the limit specified.

(3) Gasoline emissions from the barge loading and unloading facility shall not exceed 0.0039 pounds per gallon of gasoline loaded.

(b) Upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003), or if the enclosed vapor combustor unit (VCU) is installed independently of the Crude Revamp Project:

(1) Condition D.1.1(a) is not applicable.

(2) The enclosed vapor combustor unit (VCU) shall control VOC emissions from the barge loading and unloading facility (Plt ID: 129-00037) at all times when the barge loading of gasoline and crude oil is in operation and shall achieve a minimum overall VOC control efficiency (capture and destruction efficiency) of 85.0%.

(3) VOC emissions from the barge loading and unloading facility shall not exceed 6.58 lb/hr.

Compliance with these emission limits shall limit the potential to emit of VOCs to less than forty (40) tons per twelve (12) consecutive month period, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2019 Modification permitted under MSM 129-40796-00003 and MSM 129-41173-00037.
D.1.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for this facility and any control devices. Section B - Preventive Maintenance Plan contains the Permittee’s obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.1.3 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.1.1(b)(2) and (b)(3), the Permittee shall perform VOC testing (including emission rate and overall control efficiency) for the enclosed vapor combustor unit, no later than 180 days after initial startup of the enclosed vapor combustor unit or completion of the Crude Revamp Project, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(b) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

D.1.4 VOC Control

In order to assure compliance with Condition D.1.1(b) and upon completion of the Crude Revamp Project, the enclosed vapor combustor unit (VCU) shall be in operation at all times when the barge loading of gasoline and crude oil is in operation.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

D.1.5 Vapor Combustor Unit (VCU) Pilot Flame

In order to assure compliance with Condition D.1.1(b)(2), the Permittee shall continuously monitor the presence of a pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.6 Record Keeping Requirement

(a) To document the compliance status with Condition D.1.1(a)(1), the Permittee shall maintain records at the source of the volume in gallons of gasoline loaded at the barge loading and unloading facility.

(b) To document the compliance status with Condition D.1.5, the Permittee shall maintain records of continuous flame presence of the flare. The Permittee shall include in its record when presence of a pilot flame is not recorded and the reason for the lack of flame presence reading (e.g., the process did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee’s obligations with regard to the records required by this condition.

D.1.7 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.1.1(a), shall be submitted using the reporting forms located at the end of this permit, or their equivalent, no later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition. The reports submitted by the Permittee do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).
SECTION E.1 NESHAP

Emissions Unit Description:

(a) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas. Under 40 CFR 63, Subpart R this is an affected facility. Under 40 CFR 63, Subpart CC this is an affected facility.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]


(a) Pursuant to 40 CFR 63, Subpart R Table 1, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart R.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.1.2 Gasoline Distribution Facilities NESHAP [40 CFR Part 63, Subpart R][326 IAC 20-10]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart R (included as Attachment A to the operating permit), which are incorporated by reference as 326 IAC 20-10, for the emission unit(s) listed above:

(1) 40 CFR Part 63.420 (i)
(2) 40 CFR Part 63.421
(3) 40 CFR Part 63.422 (a-c)
(4) 40 CFR Part 63.425 (a-c), (e-h)
(5) 40 CFR Part 63.427 (a-b)
(6) 40 CFR Part 63.428 (b), (c), (g)(1), (h)(1-3)
SECTION E.2 NESHAP

Emissions Unit Description:

(a) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas. Under 40 CFR 63, Subpart R this is an affected facility. Under 40 CFR 63, Subpart CC this is an affected facility.

Insignificant Activities

(a) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

(1) For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.

(2) For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.

(3) For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.

(4) For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.

(5) For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.

(6) For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

(A) One (1) fixed roof cone tank, identified as Tank No. 23, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(B) One (1) fixed roof cone tank, identified as Tank No. 27, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(C) One (1) fixed roof cone tank, identified as Tank No. 28, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(D) One (1) fixed roof cone tank, identified as Tank No. 31, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(E) One (1) fixed roof cone tank, identified as Tank No. 32, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(F) One (1) tank, identified as Skid Tank, constructed in 1960, with a capacity of 576 gallons. [40 CFR 63, Subpart CC]

(G) One (1) tank, identified as Dock Tank, constructed in 1950, with a capacity of 564 gallons. [40 CFR 63, Subpart CC]
(H) One (1) upstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]

(I) One (1) downstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]

(J) Pipeline Valves: Gas Stream. [40 CFR 63, Subpart CC]

(K) Pipeline Valves: Light Liquid. [40 CFR 63, Subpart CC]

(L) Pipeline Valves: Heavy Liquid. [40 CFR 63, Subpart CC]

(M) Open Ended Valves. [40 CFR 63, Subpart CC]

(N) Flanges. [40 CFR 63, Subpart CC]

(O) Pump Seals: Light Liquid. [40 CFR 63, Subpart CC]

(P) Pump Seals: Heavy Liquid. [40 CFR 63, Subpart CC]

(Q) Drains. [40 CFR 63, Subpart CC]

(R) Vessel relief valves. [40 CFR 63, Subpart CC]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]


(a) Pursuant to 40 CFR 63.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart CC.

(b) Pursuant to 40 CFR 60.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.2.2 Petroleum Refineries NESHAP [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart CC (included as Attachment B to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 63.640
(2) 40 CFR 63.641
(3) 40 CFR 63.642
(4) 40 CFR 63.643
E.2.3 Standard of Performance for Storage Vessels for Bulk Gasoline Terminals [326 IAC 12-1] [40 CFR 60, Subpart XX][326 IAC 20-16][40 CFR 63, Subpart CC] Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart XX, which are incorporated by reference as 326 IAC 12 (included as Attachment C to the operating permit), as follows.

(1) 40 CFR Part 60.502
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio Street, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-41688-00037

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter
☐ Test Result (specify)
☐ Report (specify)
☐ Notification (specify)
☐ Affidavit (specify)
☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Phone:
Date:
PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio Street, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-41688-00037

This form consists of 2 pages         Page 1 of 2

☐ This is an emergency as defined in 326 IAC 2-7-1(12)
  • The Permittee must notify the Office of Air Quality (OAQ), within four (4) daytime
    business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
  • The Permittee must submit notice in writing or by facsimile within two (2) working days
    (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:

Control Equipment:

Permit Condition or Operation Limitation in Permit:

Description of the Emergency:

Describe the cause of the Emergency:
If any of the following are not applicable, mark N/A

<table>
<thead>
<tr>
<th>Date/Time Emergency started:</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Date/Time Emergency was corrected:</td>
<td></td>
</tr>
<tr>
<td>Was the facility being properly operated at the time of the emergency?</td>
<td>Y</td>
</tr>
<tr>
<td>Type of Pollutants Emitted: TSP, PM-10, SO₂, VOC, NOₓ, CO, Pb, other:</td>
<td></td>
</tr>
<tr>
<td>Estimated amount of pollutant(s) emitted during emergency:</td>
<td></td>
</tr>
<tr>
<td>Describe the steps taken to mitigate the problem:</td>
<td></td>
</tr>
<tr>
<td>Describe the corrective actions/response steps taken:</td>
<td></td>
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<tr>
<td>Describe the measures taken to minimize emissions:</td>
<td></td>
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<tr>
<td>If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:</td>
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</tbody>
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Form Completed by: ____________________________
Title / Position: ____________________________
Date: ____________________________
Phone: ____________________________
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio Street, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-41688-00037
Facility: Barge loading and unloading facility
Parameter: Gasoline throughput
Limit: Shall be less than 83,891,000 equivalent gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER: ____________ YEAR: ________________

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<td>This Month</td>
<td>Previous 11 Months</td>
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☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.

Deviation has been reported on:

Submitted by: ________________________________
Title / Position: ________________________________
Signature: ________________________________
Date: ________________________________
Phone: ________________________________
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio Street, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-41688-00037

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C - General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

<table>
<thead>
<tr>
<th>Permit Requirement (specify permit condition #)</th>
<th>Date of Deviation:</th>
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<td>Response Steps Taken:</td>
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<td>Response Steps Taken:</td>
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Form Completed by: ________________________________
Title / Position: ________________________________
Date: ________________________________
Phone: ________________________________
Attachment A

Part 70 Administrative Operating Permit No.: 129-41688-00037

[Downloaded from the eCFR on May 20, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

Source: 59 FR 64318, Dec. 14, 1994, unless otherwise noted.

§ 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, ET, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$$ET = CF[0.59(T_F)(1-CE)+0.17(T_E)+0.08(T_{ES})+0.038(T_I)+8.5\times10^{-6}(C)+KQ]+0.04(OE)$$

where:

- ET = 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} \text{ for bulk gasoline terminals with uncontrolled loading racks (no vapor collection and processing systems), OR}

K = (4.5 \times 10^{-9})(EF + L) \text{ for bulk gasoline terminals with controlled loading racks (loading racks that have vapor collection and processing systems installed on the emission stream);}

EF = \text{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 = \text{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 ET or EP. If the value of 0.04(OE) is greater than 5 percent of either ET or EP, then paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability;}

L = 13 \text{ 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 \text{ 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, EP, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

\[ EP = CF [6.7(TF)(1-CE) + 0.21(TE) + 0.093(TES) + 0.1(TI) + 5.31 \times 10^{-6}(C)] + 0.04(OE); \]

where:

EP = \text{emissions screening factor for pipeline breakout stations,}

and the definitions for CF, TF, CE, TE, TES, TI, 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, ET or EP, 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, ET or EP, 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.

§ 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.


§ 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).


§ 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 m\(^3\) 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 m\(^3\) 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.

§ 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.


§ 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 (Pi) for the pressure test shall be 460 mm H₂O (18 in. H₂O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H₂O (6 in. H₂O), 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

<table>
<thead>
<tr>
<th>Cargo tank or compartment capacity, liters (gal)</th>
<th>Annual certification-allowable pressure or vacuum change (Δp, Δv) in 5 minutes, mm H₂O (in. H₂O)</th>
<th>Allowable pressure change (Δp) in 5 minutes at any time, mm H₂O (in. H₂O)</th>
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</thead>
<tbody>
<tr>
<td>9,464 or more (2,500 or more)</td>
<td>25 (1.0)</td>
<td>64 (2.5)</td>
</tr>
<tr>
<td>9,463 to 5,678 (2,499 to 1,500)</td>
<td>38 (1.5)</td>
<td>76 (3.0)</td>
</tr>
<tr>
<td>5,679 to 3,785 (1,499 to 1,000)</td>
<td>51 (2.0)</td>
<td>89 (3.5)</td>
</tr>
<tr>
<td>3,782 or less (999 or less)</td>
<td>64 (2.5)</td>
<td>102 (4.0)</td>
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(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 H₂O (18 in. H₂O), 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 H₂O (5 in. H₂O).

(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. H₂ O), 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:

\[
P_F = 18 \left( \frac{18 - N}{18} \right) \left( \frac{V_s}{V_h} \right)
\]

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 H₂O (18 in. H₂O), 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

<table>
<thead>
<tr>
<th>Time interval</th>
<th>Interval pressure change, mm H₂O (in. H₂O)</th>
</tr>
</thead>
<tbody>
<tr>
<td>After 1 minute</td>
<td>28 (1.1)</td>
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<tr>
<td>After 2 minutes</td>
<td>56 (2.2)</td>
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<td>After 3 minutes</td>
<td>84 (3.3)</td>
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<td>After 4 minutes</td>
<td>112 (4.4)</td>
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<tr>
<td>After 5 minutes</td>
<td>140 (5.5)</td>
</tr>
</tbody>
</table>

(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 (Pᵢ) shall be 460 mm H₂O (18 in. H₂O), gauge. The maximum allowable 5-minute pressure change (Δp) 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.


§ 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.
§ 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.


§ 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.


§ 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]

Table 1 to Subpart R of Part 63—General Provisions Applicability to Subpart R

<table>
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<tr>
<th>Reference</th>
<th>Applies to subpart R</th>
<th>Comment</th>
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Attachment B

Part 70 Administrative Operating Permit No: 129-41688-00037

[Downloaded from the eCFR on February 7, 2020]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

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, 1996, 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, 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 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 (vii) 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, except that pressure relief devices in organic HAP service must only comply with the requirements in §63.648(j).

(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.


§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 or for other safety reasons. 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 to improve the heat content of combustion zone gas. Flare supplemental gas does not include assist air or assist steam.

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.

Pressure relief device means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices.

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), (a)(2), and (b) and 63.660(b)(2);

(ii) An external floating roof meeting the specifications of §§63.1063(a)(1)(ii), (a)(2), and (b) and 63.660(b)(2); 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
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 type of pressure relief device that is designed to re-close after the pressure relief.

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.


§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:

\[ E_A = 0.02 \Sigma EPV_1 + \Sigma EPV_2 + 0.05 \Sigma ES_1 + \Sigma ES_2 + \Sigma EGLR_1C + \Sigma EGLR_2 + (R) \Sigma EMV_1 + \Sigma EMV_2 + \Sigma EWW_1C + \Sigma EWW_2 \]
where:

\[ EA = \text{Emission rate, megagrams per year, allowed for the source.} \]

\[ 0.02 \sum EPV_1 = \text{Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in §63.641.} \]

\[ \sum EPV_2 = \text{Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in §63.641.} \]

\[ 0.05 \sum ES_1 = \text{Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in §63.641.} \]

\[ \sum ES_2 = \text{Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in §63.641.} \]

\[ 0.05 \sum EGLR_1C = \text{Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in §63.641.} \]

\[ \sum EGLR_2 = \text{Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in §63.641.} \]

\[ (R) \sum EMV_1 = \text{Sum of the residual emissions megagrams per year, from all Group 1 marine tank vessels, as defined in §63.641.} \]

\[ R = 0.03 \text{ for existing sources, 0.02 for new sources.} \]

\[ \sum EMV_2 = \text{Sum of the emissions, megagrams per year from all Group 2 marine tank vessels, as defined in §63.641.} \]

\[ \sum EWW_1C = \text{Sum of the residual emissions from all Group 1 wastewater streams, as defined in §63.641. This term is calculated for each Group 1 stream according to the equation for EWWic in §63.652(h)(6).} \]

\[ \sum EWW_2 = \text{Sum of emissions from all Group 2 wastewater streams, as defined in §63.641.} \]

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 (l)(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, 63.652, 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.


§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 (l)(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 nor identify maintenance vents in a Notification of Compliance Status report. 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 meeting requirements in paragraphs (a)(1) or (2) of this section, a 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 pounds per square inch gauge (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) is less than 10 percent.

   (iii) The equipment served by the maintenance vent contains less than 72 pounds of total volatile organic compounds (VOC).

   (iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (e.g., hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the equipment at the time of the startup, shutdown, maintenance, or inspection activity, 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.

   (v) If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in paragraphs (c)(1)(i) through (iv) of this section can be met prior to installing or removing a blind flange or similar equipment blind, the pressure in the equipment served by the maintenance vent is reduced to 2 psig or less. Active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

(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.


§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), (2), or (3) 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; or

(3) Use a cap, blind flange, plug, or a second valve for an open-ended valve or line following the requirements specified in §60.482-6(a)(2), (b) and (c).

(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.
§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:
where:

\[ C_{\text{TOC}} = \frac{\sum_{j=1}^{x} \left( \sum_{i=1}^{n} C_{i,j} \right)}{K} \]

- \( C_{\text{TOC}} \): Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.
- \( C_{i,j} \): 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) \((E_{\text{TOC}})\) shall be calculated using the following equation if Method 18 is used:

\[ E = K_2 \left[ \sum_{j=1}^{x} C_{i,j} M_j \right] Q_s \]

where:

- \( E \): Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.
- \( K_2 \): Constant, \( 5.986 \times 10^{-5} \) (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.
- \( C_{i,j} \): 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. \( C_{i,j} \) 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 \((E_{\text{TOC}})\) shall be calculated using the following equation:

\[ E_{\text{TOC}} = K_2 C_{\text{TOC}} M Q_s \]

where:

- \( E_{\text{TOC}} \): Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.
- \( K_2 \): Constant, \( 5.986 \times 10^{-5} \) (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.
- \( C_{\text{TOC}} \): 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 \( C_{\text{TOC}} \), 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.


§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.aniso.org), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824-7000, http://www.agaw.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.


§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.
§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) through (3), and (c) through (j) 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 (j) 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, and 63.180 except as provided in paragraphs (c)(1) through (12) and (e) through (j) 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.

(1) 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 of this chapter, §60.482-4a of this chapter, 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 in organic HAP service.

(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(c) of this chapter, §60.485a(c) of this chapter, 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(c) of this chapter, §60.485a(c) of this chapter, 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 disc is replaced. The owner or operator must conduct instrument monitoring, as specified in §60.485(c) of this chapter, §60.485a(c) of this chapter, 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, liquid level and pressure indicators with deadman switches, monitors, or automatic actuators. Independent, non-duplicative systems within this category count as separate redundant prevention measures.

(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 device (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 from an affected pressure relief device 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. (i) 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.

(ii) If a pilot-operated pressure relief device is used and the primary release valve is 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 required to comply only with paragraphs (j)(1) and (2) of this section for the pilot discharge vent and is not required to comply with paragraph (j)(3) of this section for the pilot-operated pressure relief device.
(iii) If a balanced bellows pressure relief device is used and the primary release valve is 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 required to comply only with paragraphs (j)(1) and (2) of this section for the bonnet vent and is not required to comply with paragraph (j)(3) of this section for the balanced bellows pressure relief device.

(iv) Both the closed vent system and control device (if applicable) referenced in paragraphs (j)(4)(i) through (iii) of this section 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.”

(v) 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.


§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:

   \[
   \% \text{CL} = \left[\frac{(\text{CL} - \text{CAN})}{\text{Ct} + \text{Cc}}\right] \times 100
   \]

   where:

   \% \text{CL} = \text{Percentage leaking connectors.}

   \text{CL} = \text{Number of connectors including nonrepairables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, appendix A.}

   \text{CAN} = \text{Number of allowable nonrepairable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, Ct.}

   \text{Ct} = \text{Total number of monitored connectors, including nonrepairables, in the process unit.}

   \text{Cc} = \text{Optional credit for removed connectors = 0.67 \times \text{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.


§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.


§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.


§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 63.650, 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) [Reserved]

(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 (i) 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:

\[ \text{Debits} = \sum_{i=1}^{n} \left( EPV_{\text{ACTUAL}} - (0.02) EPV_{i} \right) + \sum_{i=1}^{n} \left( ES_{\text{ACTUAL}} - (0.05) ES_{i} \right) + \sum_{i=1}^{n} \left( BCLR_{\text{ACTUAL}} - BCLR_{i} \right) \]

\[ + \sum_{i=1}^{n} \left( EMV_{\text{ACTUAL}} - (0.02) EMV_{i} \right) \]

where:

Debits and all terms of the equation are in units of megagrams per month, and

\[ EPV_{\text{ACTUAL}} = \text{Emissions from each Group 1 miscellaneous process vent i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(2) of this section.} \]

\[ (0.02) EPV_{i} = \text{Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(2) of this section.} \]

\[ ES_{\text{ACTUAL}} = \text{Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.} \]
(0.05) $E_{Si} = \text{Emissions from each Group 1 storage vessel } i \text{ if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.}$

$E_{GRI_{\text{ACTUAL}}} = \text{Emissions from each Group 1 gasoline loading rack } i \text{ that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(4) of this section.}$

$E_{GRI_{c}} = \text{Emissions from each Group 1 gasoline loading rack } i \text{ if the reference control technology had been applied to the uncontrolled emissions. This is calculated according to paragraph (g)(4) of this section.}$

$E_{MV_{\text{ACTUAL}}} = \text{Emissions from each Group 1 marine tank vessel } i \text{ that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(5) of this section.}$

(0.03) $E_{MVi} = \text{Emissions from each Group 1 marine tank vessel } i \text{ if the reference control technology had been applied to the uncontrolled emissions calculated according to paragraph (g)(5) of this section.}$

$n = \text{The number of Group 1 emission points being included in the emissions average. The value of } n \text{ is not necessarily the same for each kind of emission point.}$

(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 $E_{MV_{i}}$:

$$E_{MV_{i}} = \left( 2.494 \times 10^{-9} \right) Qh \left( \sum_{j=1}^{n} C_j M_j \right)$$

where:

$E_{MV_{i}} = \text{Uncontrolled process vent emission rate from miscellaneous process vent } i, \text{ megagrams per month.}$

$Q = \text{Vent stream flow rate, dry standard cubic meters per minute, measured using Methods 2, 2A, 2C, or 2D of part 60 appendix A, as appropriate.}$

$h = \text{Monthly hours of operation during which positive flow is present in the vent, hours per month.}$

$C_j = \text{Concentration, parts per million by volume, dry basis, of organic HAP } j \text{ as measured by Method 18 of part 60 appendix A.}$

$M_j = \text{Molecular weight of organic HAP } j, \text{ gram per gram-mole.}$

$n = \text{Number of organic HAP's in the miscellaneous process vent stream.}$

(A) The values of $Q, C_j, \text{ and } M_j$ shall be determined during a performance test conducted under representative operating conditions. The values of $Q, C_j, \text{ and } M_j$ 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 $Q, C_j, \text{ and } M_j$ are no longer representative, a new performance test shall be conducted to determine new representative
values of $Q$, $C_i$, 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 $EPV_{\text{actual}}$:

(A) If the vent is not controlled by a control device or pollution prevention measure, $EPV_{\text{actual}} = EPV_{iu}$, 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,

$$EPV_{\text{actual}} = EPV_{iu} \times \left(1 - \frac{\text{Percent reduction}}{100\%}\right)$$

(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 $EPV_{\text{actual}}$. 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 $EGLR_{iu}$:

$$EGLR_{iu} = \left(1.20 \times 10^{-7}\right) \frac{SPMG}{T}$$

where:

$EGLR_{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:

\[
P = \frac{\sum_{j=1}^{n} (P_j)(G_j)}{G}
\]

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

\[G = \sum_{j=1}^{n} G_j\]

\(G_j\) = 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:

\[
M = \frac{\sum_{j=1}^{n} (M_j)(G_j)}{G}
\]

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:

\[
T = \frac{\sum_{j=1}^{n} (T_j)(G_j)}{G}
\]

\(T_j\) = 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 \(EGLR_{i,e}\):

\[
EGLR_{i,e} = 1 \times 10^{-9} G
\]
G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate EGLR\textsubscript{ACTUAL}:

(A) If the gasoline loading rack is not controlled, EGLR\textsubscript{ACTUAL} = EGLR\textsubscript{iu}, where EGLR\textsubscript{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,

\[
EGLR\textsubscript{ACTUAL} = EGLR\textsubscript{iu} \left( \frac{1 - \text{Percent reduction}}{100\%} \right)
\]

(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\textsubscript{iu}:

\[
EMV\textsubscript{iu} = \sum_{i=1}^{m} (Q_i)(F_i)(P_i)
\]

where:

EMV\textsubscript{iu} = Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i, megagrams per month.

Q\textsubscript{i} = Quantity of commodity loaded (per vessel type), liters.

F\textsubscript{i} = Emission factor, megagrams per liter.

P\textsubscript{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\textsubscript{ACTUAL}:

(A) If the marine tank vessel is not controlled, EMV\textsubscript{ACTUAL} = EMV\textsubscript{iu}, where EMV\textsubscript{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,

\[
EMV\textsubscript{ACTUAL} = EMV\textsubscript{iu} \left( \frac{1 - \text{Percent reduction}}{100\%} \right)
\]
(1) 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:

\[
\text{Credits} = D \sum_{i=1}^{N} \left( (0.02) \text{EPV}_{1i}^{\text{in}} - \text{EPV}_{1i}^{\text{actual}} \right) + D \sum_{i=1}^{N} \left( \text{EPV}_{2i}^{\text{BASE}} - \text{EPV}_{2i}^{\text{actual}} \right) +

D \sum_{i=1}^{N} \left( (0.05) \text{ES}_{1i}^{\text{n}} - \text{ES}_{1i}^{\text{actual}} \right) + D \sum_{i=1}^{N} \left( \text{ES}_{2i}^{\text{BASE}} - \text{ES}_{2i}^{\text{actual}} \right) +

D \sum_{k=1}^{N} \left( \text{EGLR}_{k}^{\text{n}} - \text{EGLR}_{k}^{\text{actual}} \right) + D \sum_{k=1}^{N} \left( \text{EGLR}_{2i}^{\text{BASE}} - \text{EGLR}_{2i}^{\text{actual}} \right) +

D \sum_{k=1}^{N} \left( (0.03) \text{EMV}_{1n}^{\text{k}} - \text{EMV}_{1n}^{\text{actual}} \right) + D \sum_{k=1}^{N} \left( \text{EMV}_{2i}^{\text{BASE}} - \text{EMV}_{2i}^{\text{actual}} \right) +

D \sum_{k=1}^{N} \left( \text{EWW}_{1k}^{\text{n}} - \text{EWW}_{1k}^{\text{actual}} \right) + D \sum_{k=1}^{N} \left( \text{EWW}_{2i}^{\text{BASE}} - \text{EWW}_{2i}^{\text{actual}} \right)
\]

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.

\(\text{EPV}_{1i}^{\text{actual}}\) = 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.

\(0.02\) \(\text{EPV}_{1i}^{\text{n}}\) = Emissions from each Group 1 miscellaneous process vent \(i\) if the reference control technology had been applied to the uncontrolled emissions. \(\text{EPV}_{1i}^{\text{n}}\) is calculated according to paragraph (h)(2) of this section.

\(\text{EPV}_{2i}^{\text{BASE}}\) = Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

\(\text{EPV}_{2i}^{\text{actual}}\) = Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

\(\text{ES}_{1i}^{\text{n}}\) = 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.

\(0.05\) \(\text{ES}_{1i}^{\text{actual}}\) = Emissions from each Group 1 storage vessel \(i\) if the reference control technology had been applied to the uncontrolled emissions. \(\text{ES}_{1i}^{\text{actual}}\) is calculated according to paragraph (h)(3) of this section.

\(\text{ES}_{2i}^{\text{BASE}}\) = Emissions from each Group 2 storage vessel; at the baseline date, as calculated in paragraph (h)(3) of this section.

\(\text{ES}_{2i}^{\text{actual}}\) = Emissions from each Group 2 storage vessel that is controlled, calculated according to paragraph (h)(3) of this section.

\(\text{EGLR}_{k}^{\text{n}}\) = Emissions for each Group 1 miscellaneous vent \(k\) that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

\(\text{EGLR}_{k}^{\text{actual}}\) = Emissions for each Group 1 miscellaneous vent \(k\) if the reference control technology had been applied to the uncontrolled emissions. \(\text{EGLR}_{k}^{\text{actual}}\) is calculated according to paragraph (h)(2) of this section.

\(\text{EGLR}_{2i}^{\text{BASE}}\) = Emissions from each Group 2 miscellaneous vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

\(\text{EGLR}_{2i}^{\text{actual}}\) = Emissions from each Group 2 miscellaneous vent that is controlled, calculated according to paragraph (h)(2) of this section.

\(\text{EMV}_{1n}^{\text{k}}\) = Emissions for each Group 1 storage vessel \(k\) that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

\(\text{EMV}_{1n}^{\text{actual}}\) = Emissions for each Group 1 storage vessel \(k\) if the reference control technology had been applied to the uncontrolled emissions. \(\text{EMV}_{1n}^{\text{actual}}\) is calculated according to paragraph (h)(3) of this section.

\(\text{EMV}_{2i}^{\text{BASE}}\) = Emissions from each Group 2 storage vessel; at the baseline date, as calculated in paragraph (h)(3) of this section.

\(\text{EMV}_{2i}^{\text{actual}}\) = Emissions from each Group 2 storage vessel that is controlled, calculated according to paragraph (h)(3) of this section.

\(\text{EWW}_{1k}^{\text{n}}\) = Emissions for each Group 1 miscellaneous vent \(k\) that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

\(\text{EWW}_{1k}^{\text{actual}}\) = Emissions for each Group 1 miscellaneous vent \(k\) if the reference control technology had been applied to the uncontrolled emissions. \(\text{EWW}_{1k}^{\text{actual}}\) is calculated according to paragraph (h)(2) of this section.

\(\text{EWW}_{2i}^{\text{BASE}}\) = Emissions from each Group 2 miscellaneous vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

\(\text{EWW}_{2i}^{\text{actual}}\) = Emissions from each Group 2 miscellaneous vent that is controlled, calculated according to paragraph (h)(2) of this section.
(0.05) ES_{1u} = \text{Emissions from each Group 1 storage vessel } i \text{ if the reference control technology had been applied to the uncontrolled emissions. } ES_{1u} \text{ is calculated according to paragraph (h)(3) of this section.}

ES_{2\text{ACTUAL}} = \text{Emissions from each Group 2 storage vessel } i \text{ that is controlled, calculated according to paragraph (h)(3) of this section.}

ES_{2\text{BASE}} = \text{Emissions from each Group 2 storage vessel } i \text{ at the baseline date, as calculated in paragraph (h)(3) of this section.}

EGLR_{1\text{ACTUAL}} = \text{Emissions from each Group 1 gasoline loading rack } i \text{ that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.}

EGLR_{1c} = \text{Emissions from each Group 1 gasoline loading rack } i \text{ if the reference control technology had been applied to the uncontrolled emissions. } EGLR_{1u} \text{ is calculated according to paragraph (h)(4) of this section.}

EGLR_{2\text{ACTUAL}} = \text{Emissions from each Group 2 gasoline loading rack } i \text{ that is controlled, calculated according to paragraph (h)(4) of this section.}

EGLR_{2\text{BASE}} = \text{Emissions from each Group 2 gasoline loading rack } i \text{ at the baseline date, as calculated in paragraph (h)(4) of this section.}

EMV_{1\text{ACTUAL}} = \text{Emissions from each Group 1 marine tank vessel } i \text{ that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.}

(0.03)EMV_{1u} = \text{Emissions from each Group 1 marine tank vessel } i \text{ if the reference control technology had been applied to the uncontrolled emissions. } EMV_{1u} \text{ is calculated according to paragraph (h)(5) of this section.}

EMV_{2\text{ACTUAL}} = \text{Emissions from each Group 2 marine tank vessel } i \text{ that is controlled, calculated according to paragraph (h)(5) of this section.}

EMV_{2\text{BASE}} = \text{Emissions from each Group 2 marine tank vessel } i \text{ at the baseline date, as calculated in paragraph (h)(5) of this section.}

EWW_{1\text{ACTUAL}} = \text{Emissions from each Group 1 wastewater stream } i \text{ that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.}

EWW_{1c} = \text{Emissions from each Group 1 wastewater stream } i \text{ if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.}

EWW_{2\text{ACTUAL}} = \text{Emissions from each Group 2 wastewater stream } i \text{ that is controlled, calculated according to paragraph (h)(6) of this section.}

EWW_{2\text{BASE}} = \text{Emissions from each Group 2 wastewater stream } i \text{ at the baseline date, calculated according to paragraph (h)(6) of this section.}

n = \text{Number of Group 1 emission points included in the emissions average. The value of } n \text{ is not necessarily the same for each kind of emission point.}

m = \text{Number of Group 2 emission points included in the emissions average. The value of } m \text{ 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\textsubscript{iu}, shall be calculated according to the procedures and equation for EPV\textsubscript{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, EPV\textsubscript{1\text{ACTUAL}}, shall be calculated according to the following equation:

\[
EPV\textsubscript{1\text{ACTUAL}} = EPV\textsubscript{1\text{iu}} \times \left(1 - \frac{\text{Nominal efficiency \%}}{100}\right)
\]

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, EPV\textsubscript{2\text{ACTUAL}}:

(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,

\[
EPV\textsubscript{2\text{iu}} = EPV\textsubscript{2\text{iu}} \times \left(1 - \frac{\text{Percent reduction}}{100}\right)
\]

(1) EPV\textsubscript{2\text{iu}} shall be calculated according to the equations and procedures for EPV\textsubscript{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, EPV\textsubscript{2\text{iu}} shall be calculated prior to that recovery device. The equation for EPV\textsubscript{iu} in paragraph (g)(2)(ii) of this section shall be used to calculate EPV\textsubscript{2\text{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,

\[
EPV\textsubscript{2\text{ACTUAL}} = EPV\textsubscript{2\text{iu}} \times \left(1 - \frac{\text{Nominal efficiency \%}}{100}\right)
\]

(iv) Emissions from Group 2 process vents at baseline, EPV\textsubscript{2\text{BASE}}, shall be calculated as follows:
(A) If the process vent was uncontrolled on November 15, 1990, \( EPV_{2\text{BASE}} = EPV_{2\text{iu}} \), and shall be calculated according to the procedures and equation for \( EPV_{2\text{iu}} \) in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the process vent was controlled on November 15, 1990,

\[
EPV_{2\text{BASE}} = EPV_{2\text{iu}} \left( 1 - \frac{\text{Percent reduction}\%}{100\%} \right)
\]

where \( EPV_{2\text{iu}} \) is calculated according to the procedures and equation for \( EPV_{2\text{iu}} \) 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)(f) 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, \( EPV_{2\text{BASE}} = EPV_{2\text{iu}} \), where \( EPV_{2\text{iu}} \) 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) For storage vessels complying with §63.646:

(A) 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 (6).

(B) 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).

(C) 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).

(ii) For storage vessels complying with §63.660:

(A) Section 63.1063(a)(1)(i), (a)(2), and (b) or §63.1063(a)(1)(i) and (b) shall apply instead of §63.119(b) in §63.150(h)(3) of subpart G.

(B) Section 63.1063(a)(1)(ii), (a)(2), and (b) shall apply instead of §63.119(c) in §63.150(h)(3) of subpart G.

(C) Section 63.1063(a)(1)(i), (a)(2), and (b) or §63.1063(a)(1)(i) and (b) shall apply instead of §63.119(d) in §63.150(h)(3) of subpart G.

(4) Emissions from gasoline loading racks shall be determined as follows:

(i) Uncontrolled emissions from Group 1 gasoline loading racks, \( EGLR_{1\text{iu}} \), shall be calculated according to the procedures and equations for \( EGLR_{1\text{iu}} \) 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, \( EGLR_{1\text{ic}} \), 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; \( EGLR_{1\text{ACTUAL}} \), shall be calculated according to the following equation:

\[
EGLR_{1\text{ACTUAL}} = EGLR_{1\text{iu}} \left( 1 - \frac{\text{Nominal efficiency}}{100\%} \right)
\]
(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $E_{GLR2_{\text{actual}}}$:

(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,

$$E_{GLR2_{\text{actual}}} = E_{GLR2_{iu}} \left(1 - \frac{\text{Percent reduction}}{100}\right)$$

(1) $E_{GLR2_{iu}}$ shall be calculated according to the equations and procedures for $E_{GLR2_{iu}}$ 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,

$$E_{GLR2_{\text{actual}}} = E_{GLR2_{iu}} \left(1 - \frac{\text{Nominal efficiency}}{100}\right)$$

(v) Emissions from Group 2 gasoline loading racks at baseline, $E_{GLR2_{\text{base}}}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $E_{GLR2_{\text{base}}} = E_{GLR2_{iu}}$, and shall be calculated according to the procedures and equations for $E_{GLR2_{iu}}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack was controlled on November 15, 1990,

$$E_{GLR2_{\text{base}}} = E_{GLR2_{iu}} \left(1 - \frac{\text{Percent reduction}}{100}\right)$$

where $E_{GLR2_{iu}}$ is calculated according to the procedures and equations for $E_{GLR2_{iu}}$ 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, $EMV_{1_{iu}}$, shall be calculated according to the procedures and equations for $EMV_{1_{iu}}$ 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, $EMV_{1_{\text{actual}}}$, shall be calculated according to the following equation:

$$EMV_{1_{\text{actual}}} = EMV_{1_{iu}} \left(1 - \frac{\text{Nominal efficiency}}{100}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 marine tank vessels, $EMV_{2_{\text{actual}}}$:
(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,

\[
EMV_{2,\text{Actual}} = EMV_{2,\text{iu}} \left(1 - \frac{\text{Percent reduction}}{100}\right)
\]

(1) \(EMV_{2,\text{iu}}\) shall be calculated according to the equations and procedures for \(EMV_{2,\text{iu}}\) 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,

\[
EMV_{2,\text{Actual}} = EMV_{2,\text{iu}} \left(1 - \frac{\text{Nominal efficiency}}{100}\right)
\]

(iv) Emissions from Group 2 marine tank vessels at baseline, \(EMV_{2,\text{BASE}}\), shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, \(EMV_{2,\text{BASE}}\) equals \(EMV_{2,\text{iu}}\), and shall be calculated according to the procedures and equations for \(EMV_{2,\text{iu}}\) in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel was controlled on November 15, 1990,

\[
EMV_{2,\text{BASE}} = EMV_{2,\text{iu}} \left(1 - \frac{\text{Percent reduction}}{100}\right)
\]

where \(EMV_{2,\text{iu}}\) is calculated according to the procedures and equations for \(EMV_{2,\text{iu}}\) 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)(ii) 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 \(EWW_{ic}\):
where:

\( EWW_{i\text{c}} = \left(6.0 \times 10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left(1 - F_{r_m}\right) F_{e_m} HAP_{im} + (0.05) \left(6.0 \times 10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left( F_{r_m} HAP_{im}\right) \)

\( EWW_{i\text{c}} = \) 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.

\( F_{r_m} = \) Fraction removed of organic HAP \( m \) in wastewater, from table 7 of this subpart, dimensionless.

\( F_{e_m} = \) Fraction emitted of organic HAP \( m \) in wastewater from table 7 of this subpart, dimensionless.

\( s = \) Total number of organic HAPs 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 HAPs 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: \( HAP_{im} = C_{im} F_{m} \), where \( F_{m} \) 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 \( EWW_{i\text{ACTUAL}} \) 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:

\( EWW_{i\text{ACTUAL}} = \left(6.0 \times 10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[F_{e_m} HAP_{pm} (1 - PR_{pm})\right] + 0.05 \left(6.0 \times 10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[HAP_{pm} PR_{pm}\right] \)
Where:

\[ EWW_{\text{ACTUAL}} \] = Monthly wastewater stream emission rate if wastewater stream \( i \) is treated to a level more stringent than the reference control technology, megagrams per month.

\[ PR_{m} \] = 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, as calculated by:

\[
PR_{m} = \frac{HAP_{\text{in}} - HAP_{\text{out}}}{HAP_{\text{in}}}
\]

Where:

\[ HAP_{\text{in}} \] = 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.

\[ HAP_{\text{out}} \] = 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:

\[
EWW_{\text{ACTUAL}} = \left( 6.0 \times 10^{-9} \right) Q_i H_i \sum_{m=1}^{N} \left[ \frac{HAP_{\text{in}}}{HAP_{\text{out}}} (1 - A_m) \right] + \left( 1 - \frac{\text{Nominal efficiency} \times \%}{100} \right) \left( 6.0 \times 10^{-9} \right) Q_i H_i \sum_{m=1}^{N} [HAP_{\text{in}} A_m]
\]

Where:

\[ \text{Nominal efficiency} \] = 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 \( PR_m \). If the value of \( PR_m \) 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 \( EWW_{\text{ACTUAL}} \) according to paragraph (h)(6)(iii)(B) of this section rather than paragraph (h)(6)(iii)(A) of this section. If \( PR_m \) 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:
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 \( EWW_{2\text{iBASE}} \) for each Group 2 wastewater stream \( i \) that on November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

\[
EWW_{2\text{iBASE}} = \left( 6.0 \times 10^{-8} \right) Q_2 H_i \sum_{n=1}^{i} [ F_{em} HAP_{ie} \left( 1 - FR_{n} \right) ] + \left( 1 - \frac{\text{Nominal efficiency}}{100} \right) \left( 6.0 \times 10^{-8} \right) Q_2 H_i \sum_{n=1}^{i} [ HAP_{ie} P_{Rn} ]
\]

Where:

\( EWW_{2\text{iBASE}} = \) Monthly wastewater stream emission rate if wastewater stream \( i \) is not correctly suppressed, megagrams per month.

\( Q_2, H_i, s, F_{em}, \) and \( HAP_{ie} \) 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 \( EWW_{2\text{iBASE}} \) for each Group 2 wastewater stream \( i \) on November 15, 1990 was correctly suppressed. \( EWW_{2\text{iBASE}} \) 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.

\[
EWW_{2\text{iBASE}} = \left( 6.0 \times 10^{-8} \right) Q_2 H_i \sum_{n=1}^{i} [ F_{em} HAP_{ie} ]
\]

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, \( EWW_{2\text{ACTUAL}} \) shall be calculated according to the equation for \( EWW_{2\text{BASE}} \) in paragraph (h)(6)(v) of this section. \( EWW_{2\text{ACTUAL}} \) 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:

\[ E_a = \frac{0.0416}{10^6 \times m} \left[ \sum_{p=1}^{m} V_{ap} \left( \sum_{i=1}^{n} C_{api} MW_i \right) \right] \]

\[ E_b = \frac{0.0416}{10^6 \times m} \left[ \sum_{p=1}^{m} V_{bp} \left( \sum_{i=1}^{n} C_{bpi} MW_i \right) \right] \]

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.
- \( C_{api} \) = 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.
- \( C_{bpi} \) = 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:

\[ R = \frac{E_b - E_a}{E_b} \times 100 \]

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.
Ea = 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.

\[
\text{Percent reduction} = \left( \frac{E_B \times P_B}{E_{pp} \times P_{pp}} \right) \times 100\%
\]

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:

$$E_B = \sum_{i=1}^{n} \left[ 6.0 \times 10^{-8} Q_{Bi} H_{Bi} \sum_{m=1}^{s} F_{em} HAP_{Em} \right]$$

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 $i$.

$F_{em}$ = Fraction emitted of organic HAP $m$ in wastewater from table 7 of this subpart, dimensionless.

$HAP_{Em}$ = 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:

$$E_{pp} = \sum_{i=1}^{n} \left[ 6.0 \times 10^{-8} Q_{ppi} H_{ppi} \sum_{m=1}^{s} F_{em} HAP_{ppim} \right]$$

where $n$, $Q$, $H$, $s$, $F_{em}$, 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 (l)(1) through (l)(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.


§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.


§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.
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.

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.

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.

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.

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.
§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).

(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 (f)(1)(i)(A)(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 either §63.646 or §63.660 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 or §63.660 as applicable, 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 or §63.660, as applicable, 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. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) in
accordance with §63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

(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. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface in accordance with §63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

(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 and 63.116(c), 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. If the performance test is submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) in accordance with §63.655(h)(9), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted.

(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, for data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test, you must submit the results in accordance with §63.655(h)(9) by the date that you submit the Notification of Compliance Status, and you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the Notification of Compliance Status. All other performance test results must be reported in the Notification of Compliance Status.

(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, unless the results are required to be submitted electronically by §63.655(h)(9). For performance evaluation results required to be submitted through CEDRI, submit the results in accordance with §63.655(h)(9) by the date that you submit the Notification of Compliance Status and include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the Notification of Compliance Status.

(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 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 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
the 10th 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 (iv) 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 pilot-operated pressure relief devices in organic HAP service, report each pressure release to the atmosphere through the pilot vent that equals or exceeds 72 pounds of VOC per day, including duration of the pressure release through the pilot vent and estimate of the mass quantity of each organic HAP released.

(iv) 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; owners or operators
complying with §63.643(c)(1)(v) must report each venting event conducted under those provisions and include an explanation for each event as to why utilization of this alternative was required.

(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 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) or §63.1063(d)(3). 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) [Reserved]

(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, each owner or operator shall submit the following information to the EPA’s Compliance and Emissions Data Reporting Interface (CEDRI) on a quarterly basis. (CEDRI can be accessed through the EPA’s Central Data Exchange (CDX) (https://cdx.epa.gov/). The first quarterly report must be submitted once the owner or operator has obtained 12 months of data. The first quarterly report must cover the period beginning on the compliance date that is specified in Table 11 of this subpart and ending on March 31, June 30, September 30 or December 31, whichever date is the first date that occurs after the owner or operator has obtained 12 months of data (i.e., the first quarterly report will contain between 12 and 15 months of data). Each subsequent quarterly report must cover one of the following reporting periods: Quarter 1 from January 1 through
March 31; Quarter 2 from April 1 through June 30; Quarter 3 from July 1 through September 30; and Quarter 4 from October 1 through December 31. Each quarterly report must be electronically submitted no later than 45 calendar days following the end of the reporting period.

(i) Facility name and address.

(ii) Year and reporting quarter (i.e., Quarter 1, Quarter 2, Quarter 3, or Quarter 4).

(iii) For the first reporting period and for any reporting period in which a passive monitor is added or moved, for each passive monitor: The latitude and longitude location coordinates; the sampler name; and identification of the type of sampler (i.e., regular monitor, extra monitor, duplicate, field blank, inactive). 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.

(iv) The beginning and ending dates for each sampling period.

(v) Individual sample results for benzene reported in units of µg/m³ for each monitor for each sampling period that ends during the reporting period. Results below the method detection limit shall be flagged as below the detection limit and reported at the method detection limit.

(vi) Data flags that indicate each monitor that was skipped for the sampling period, if the owner or operator uses an alternative sampling frequency under §63.658(e)(3).

(vii) Data flags for each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part. For each outlier, the owner or operator must submit the individual sample result of the outlier, as well as the evidence used to conclude that the result is an outlier.

(viii) The biweekly concentration difference (Δc) for benzene for each sampling period and the annual average Δc for benzene for each sampling period.

(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) Unless otherwise specified by this subpart, 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) Unless otherwise specified by this subpart, 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.

(10) Extensions to electronic reporting deadlines. (i) If you are required to electronically submit a report through the Compliance and Emissions Data Reporting Interface (CEDRI) in the EPA's Central Data Exchange (CDX), and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description identifying the date(s) and time(s) the CDX or CEDRI were unavailable when you attempted to access it in the 5 business days prior to the submission deadline; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(ii) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. For the purposes of this paragraph, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility. If you intend to assert a claim of force majeure, you must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(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; or

(C) All values that meet the set criteria for variation from previously recorded values using an automated data compression recording system.

(1) The automated data compression recording system shall be designed to:

(i) Measure the operating parameter value at least once every hour.

(ii) Record at least 24 values each day during periods of operation.

(iii) Record the date and time when monitors are turned off or on.
(iv) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

(v) Compute daily average values of the monitored operating parameter based on recorded data.

(2) 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 demonstration that the system meets all criteria of paragraph (i)(3)(ii)(C)(1) of this section.

(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.

(i) Identification of all petroleum refinery process unit heat exchangers at the facility and the average annual HAP concentration of process fluid or intervening cooling fluid estimated when developing the Notification of Compliance Status report.
(ii) Identification of all heat exchange systems subject to the monitoring requirements in §63.654 and identification of all heat exchange systems that are exempt from the monitoring requirements according to the provisions in §63.654(b). For each heat exchange system that is subject to the monitoring requirements in §63.654, this must include identification of all heat exchangers within each heat exchange system, and, for closed-loop recirculation systems, the cooling tower included in each heat exchange system.

(iii) Results of the following monitoring data for each required monitoring event:

(A) Date/time of event.

(B) Barometric pressure.

(C) El Paso air stripping apparatus water flow milliliter/minute (ml/min) and air flow, ml/min, and air temperature, °Celsius.

(D) FID reading (ppmv).

(E) Length of sampling period.

(F) Sample volume.


(iv) The date when a leak was identified, the date the source of the leak was identified, and the date when the heat exchanger was repaired or taken out of service.

(v) If a repair is delayed, the reason for the delay, the schedule for completing the repair, the heat exchange exit line flow or cooling tower return line average flow rate at the monitoring location (in gallons/minute), and the estimate of potential strippable hydrocarbon emissions for each required monitoring interval during the delay of repair.

(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 5-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. For each pilot-operated pressure relief device subject to the requirements at §63.648(j)(4)(ii), the owner or operator shall keep the records specified in paragraph (i)(11)(iv) 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 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.

(iv) For pilot-operated pressure relief devices, general or release-specific records for estimating the quantity of VOC released from the pilot vent during a release event, and records of calculations used to determine the quantity of specific HAP released for any event or series of events in which 72 or more pounds of VOC are released in a day.

(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 paragraphs (i)(12)(i) through (vi) 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, is 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), records used to estimate the total quantity of VOC in the equipment and the type and size limits of equipment that contain less than 72 pounds of VOC at the time of maintenance vent opening. For each maintenance vent opening for which the deinventory procedures specified in paragraph (i)(12)(i) of this section are not followed or for which the equipment opened exceeds the type and size limits established in the records specified in this paragraph, 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.

(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.

(vi) If complying with the requirements of §63.643(c)(1)(v), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and lower explosive limit of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.
§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.


§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 or less determined on a rolling 60-event average; or

(ii) An average vessel temperature of 220 degrees Fahrenheit or less 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 or less for each decoking event; or
(ii) A vessel temperature of 218 degrees Fahrenheit or less 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 each day the unit is operated 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 prior to complying with the applicable requirements in paragraph (a) of this section must meet the requirements in either paragraph (e)(1) or (e)(2) of this section or, if applicable, the requirements in paragraph (e)(3) of this section. The owner or operator of a delayed coking unit using the “water overflow” method of coke cooling subject to this paragraph shall determine the coke drum vessel temperature as specified in paragraphs (c) and (d) of this section and shall not otherwise drain or vent the coke drum until the coke drum vessel temperature is at or below the applicable limits in paragraph (a)(1)(ii) or (a)(2)(ii) of this section.

(1) The overflow water must be directed to a separator or similar disengaging device that is operated in a manner to prevent entrainment of gases from the coke drum vessel to the overflow water storage tank. Gases from the separator or disengaging device must be routed to a closed blowdown system or otherwise controlled following the requirements for a Group 1 miscellaneous process vent. The liquid from the separator or disengaging device must be hardpiped to the overflow water storage tank or similarly transported to prevent exposure of the overflow water to the atmosphere. The overflow water storage tank may be an open or uncontrolled 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.

(2) The overflow water must be directed to a storage vessel meeting the requirements for storage vessels in subpart SS of this part.
(3) Prior to November 26, 2020, if the equipment needed to comply with paragraphs (e)(1) or (2) of this section are not installed and operational, you must comply with all of the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) The temperature of the coke drum, measured according to paragraph (c) of this section, must be 250 degrees Fahrenheit or less prior to initiation of water overflow and at all times during the water overflow.

(ii) The overflow water must be hardpipied to the overflow water storage tank or similarly transported to prevent exposure of the overflow water to the atmosphere.

(iii) The overflow water storage tank may be an open or uncontrolled fixed-roof tank provided that all of the following requirements are met.

(A) A submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank.

(B) The liquid level in the storage tank is at least 6 feet above the submerged fill pipe outlet at all times during water overflow.

(C) The temperature of the contents in the storage tank remain below 150 degrees Fahrenheit at all times during water overflow.

(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, as amended at 83 FR 60718, Nov. 26, 2018]

§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. For this subpart, an additional monitor is not required if the only emission sources within 50 meters of the monitoring boundary are equipment leak sources satisfying all of the conditions in paragraphs (c)(1)(i) through (iv) of this section.

(i) The equipment leak sources in organic HAP service within 50 meters of the monitoring boundary are limited to valves, pumps, connectors, sampling connections, and open-ended lines. If compressors, pressure relief devices, or
agitators in organic HAP service are present within 50 meters of the monitoring boundary, the additional passive monitoring location specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used.

(ii) All equipment leak sources in gas or light liquid service (and in organic HAP service), including valves, pumps, connectors, sampling connections and open-ended lines, must be monitored using EPA Method 21 of 40 CFR part 60, appendix A-7 no less frequently than quarterly with no provisions for skip period monitoring, or according to the provisions of §63.11(c) Alternative Work practice for monitoring equipment for leaks. For the purpose of this provision, a leak is detected if the instrument reading equals or exceeds the applicable limits in paragraphs (c)(1)(ii)(A) through (E) of this section:

(A) For valves, pumps or connectors at an existing source, an instrument reading of 10,000 ppmv.

(B) For valves or connectors at a new source, an instrument reading of 500 ppmv.

(C) For pumps at a new source, an instrument reading of 2,000 ppmv.

(D) For sampling connections or open-ended lines, an instrument reading of 500 ppmv above background.

(E) For equipment monitored according to the Alternative Work practice for monitoring equipment for leaks, the leak definitions contained in §63.11 (c)(6)(i) through (iii).

(iii) All equipment leak sources in organic HAP service, including sources in gas, light liquid and heavy liquid service, must be inspected using visual, auditory, olfactory, or any other detection method at least monthly. A leak is detected if the inspection identifies a potential leak to the atmosphere or if there are indications of liquids dripping.

(iv) All leaks identified by the monitoring or inspections specified in paragraphs (c)(1)(ii) or (iii) of this section must be repaired no later than 15 calendar days after it is detected with no provisions for delay of repair. If a repair is not completed within 15 calendar days, the additional passive monitor specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used.

(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) If there are 19 or fewer monitoring locations, the owner or operator shall collect at least one co-located duplicate sample per sampling period and at least one field blank per sampling period. If there are 20 or more monitoring locations, the owner or operator shall collect at least two co-located duplicate samples per sampling period and at least one field blank per sampling period. The co-located duplicates may be collected at any 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)(2) 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 8.3.1 through 8.3.3 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 µg/m³, 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 µg/m³ 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 µg/m³ 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 µg/m³ 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 µg/m³ for 2 years (i.e., 4 consecutive semiannual 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 µg/m³, 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 µg/m³, 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 µg/m³. If any sample collected during this quarter is above 0.9 µg/m³, 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 µg/m³.
(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. Co-located samples must be averaged together for the purposes of determining the benzene concentration for that sampling location, and, if applicable, for determining Δc. 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 and zero as the lowest sample result when calculating Δc.

(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 (µg/m3) on an annual average basis. If the annual average Δc value for benzene is less than or equal to 9 µg/m3, the concentration is below the action level. If the annual average Δc value for benzene is greater than 9 µg/m3, 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 µg/m3 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 µg/m³ 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 for comparison with the 9 µg/m³ action level using the requirements specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δci using the following equation.

\[ \Delta c_i = MFC_i - NFS_i - UB \]

Where:

\( \Delta c_i \) = The fenceline concentration, corrected for background, at measurement location i, micrograms per cubic meter (µg/m³).

MFCi = The measured fenceline concentration at measurement location i, µg/m³.

NFSi = 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, µg/m³. For monitoring locations that are not included in the site-specific monitoring plan as impacted by a near-field source, use NFSi = 0 µg/m³.

UB = The uniform background concentration determined using the additional measurements included in the site-specific monitoring plan, µg/m³. If no additional measurements are specified in the site-specific monitoring plan for determining the uniform background concentration, use UB = 0 µg/m³.

(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 NFSi 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 $\Delta c$ for the monitoring period as the maximum value of $\Delta c_i$ 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.

§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 storing liquid with a maximum true vapor pressure less than 76.6 kilopascals (11.1 pounds per square inch) that is part of a new or existing source shall comply with either the requirements in subpart WW or SS of this part according to the requirements in paragraphs (a) through (i) of this section and the owner or operator of a Group 1 storage vessel storing liquid with a maximum true vapor pressure greater than or equal to 76.6 kilopascals (11.1 pounds per square inch) that is part of a new or existing source shall comply with the requirements in subpart 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, 1811 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.ag.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. If the floating roof storage vessel does not meet the requirements of §63.1063(a)(2)(i) through (a)(2)(viii) as of June 30, 2014, these requirements do not apply until the next time the vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first.

(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)(viii) 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) For storage vessels previously subject to requirements in §63.646, initial inspection requirements in §63.1063(c)(1) and (c)(2)(i) (i.e., those related to the initial filling of the storage vessel) or in §63.983(b)(1)(i)(A), as applicable, are not required. Failure to perform other 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) or paragraph (iii) of this section 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 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).

(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.


§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 (k)(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 \((\text{Btu/scf})\) 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.* Except as provided in paragraph (f)(1) of this section, 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 \((\text{Btu/ft}^2)\) 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.

(1) If the only assist air provided to a specific flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, the owner or operator shall comply only with the \( NHV_{cz} \) operating limit in paragraph (e) of this section for that flare.

(2) [Reserved]
(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 conduct an initial visible emissions demonstration using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A-7. The initial visible emissions demonstration should be conducted the first time regulated materials are routed to the flare. 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 for each day regulated material is routed to the flare, 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 while regulated material is routed to the flare, 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. Daily 5-minute Method 22 observations are not required to be conducted for days the flare does not receive any regulated material.

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 flare supplemental 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 premix assist air and perimeter assist air used with the flare. Flow monitoring system requirements and acceptable alternatives are provided in paragraphs (i)(1) through (6) of this section.

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.

\[
Q_{vol} = \frac{Q_{mass} \times 385.3}{MWt}
\]

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.
MWt = 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.

(5) Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

(6) For perimeter assist air intentionally entrained in lower and/or upper steam, the monitored steam flow rate and the maximum design air-to-steam volumetric flow ratio of the entrainment system may be used to determine the assist air flow rate.

(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 (iii) 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 (i) 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 Vtip operating limits. The owner or operator shall determine \( V_{tp} \) 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 \( V_{tp} \) shall be calculated using the following equation.

\[
V_{tp} = \frac{Q_{cum}}{Area \times 900}
\]

Where:

\( V_{tp} \) = Flare tip velocity, feet per second.

\( Q_{cum} \) = Cumulative volumetric flow over 15-minute block average period, standard 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 \( V_{tp} \) 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.

\[
NHV_{vg} = \sum_{i=1}^{n} x_i NHV_i
\]

Where:
NHV_{vg} = \text{Net heating value of flare vent gas, Btu/scf.}

i = \text{Individual component in flare vent gas.}

n = \text{Number of components in flare vent gas.}

x_i = \text{Concentration of component } i \text{ in flare vent gas, volume fraction.}

NHV_i = \text{Net heating value of component } i \text{ 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.

\[ NHV_{vg} = NHV_{measured} + 938x_{H2} \]

Where:

NHV_{vg} = \text{Net heating value of flare vent gas, Btu/scf.}

NHV_{measured} = \text{Net heating value of flare vent gas stream as measured by the continuous net heating value monitoring system, Btu/scf.}

x_{H2} = \text{Concentration of hydrogen in flare vent gas at the time the sample was input into the net heating value monitoring system, volume fraction.}

938 = \text{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) \text{Feed-forward calculation method. When calculating NHV}_{vg} \text{ 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 NHVvg 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 NHVvg 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 (l)(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 (NHVcz) 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 NHVcz 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, NHVcz = NHVvg.

\[
NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{Q_{vg} + Q_{s} + Q_{a, premix}}
\]

Where:

NHVcz = Net heating value of combustion zone gas, Btu/scf.

NHVvg = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.
Q_{vg} = \text{Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.}

Q_s = \text{Cumulative volumetric flow of total steam during the 15-minute block period, scf.}

Q_{a,premix} = \text{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 (l)(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 flare supplemental gas flow additions to the flare must determine the 15-minute block average NHV_{cz} using the following equation.

\[ NHV_{cz} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG}}{(Q_{vg} + Q_s + Q_{a,premix})} \]

Where:

NHV_{cz} = \text{Net heating value of combustion zone gas, Btu/scf.}

NHV_{vg} = \text{Net heating value of flare vent gas for the 15-minute block period, Btu/scf.}

Q_{vg} = \text{Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.}

Q_{NG2} = \text{Cumulative volumetric flow of flare supplemental gas during the 15-minute block period, scf.}

Q_{NG1} = \text{Cumulative volumetric flow of flare supplemental gas 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} = \text{Net heating value of flare supplemental gas for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.}

Q_s = \text{Cumulative volumetric flow of total steam during the 15-minute block period, scf.}

Q_{a,premix} = \text{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.

\[ NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter})} \]

Where:

NHV_{dil} = \text{Net heating value dilution parameter, Btu/ft}^2.

NHV_{vg} = \text{Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.}

Q_{vg} = \text{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

\[
Diam = 2 \times \sqrt{\frac{\text{Area}}{\pi}}.
\]

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

Q_{a,\text{premix}} = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

Q_{a,\text{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 (l)(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 flare supplemental 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.

\[
\text{NHV}_{dil} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG}}{(Q_{vg} + Q_s + Q_{a,\text{premix}} + Q_{a,\text{perimeter}}) \times \text{Diam}}
\]

Where:

\( \text{NHV}_{dil} \) = Net heating value dilution parameter, Btu/ft².

\( \text{NHV}_{vg} \) = 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 flare supplemental gas during the 15-minute block period, scf.

\( Q_{NG1} \) = Cumulative volumetric flow of flare supplemental gas 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., \( Q_{NG1} = Q_{NG2} \).

\( \text{NHV}_{NG} \) = Net heating value of flare supplemental gas for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

\( \text{Diam} \) = 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

\[
\text{Diam} = 2 \times \sqrt{\frac{\text{Area}}{\pi}}.
\]

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

Q_{a,\text{premix}} = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

Q_{a,\text{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 (7) 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)(3)(ii)(A) through (E) 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 a 15-minute block average and 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 based on a 15-minute block average 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 correct 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.


§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

<table>
<thead>
<tr>
<th>Chemical name</th>
<th>CAS No.¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benzene</td>
<td>71432</td>
</tr>
<tr>
<td>Biphenyl</td>
<td>92524</td>
</tr>
<tr>
<td>Butadiene (1,3)</td>
<td>106990</td>
</tr>
<tr>
<td>Carbon disulfide</td>
<td>75150</td>
</tr>
<tr>
<td>Carbonyl sulfide</td>
<td>463581</td>
</tr>
<tr>
<td>Cresol (mixed isomers²)</td>
<td>1319773</td>
</tr>
<tr>
<td>Cresol (m-)</td>
<td>108394</td>
</tr>
<tr>
<td>Cresol (o-)</td>
<td>95487</td>
</tr>
<tr>
<td>Cresol (p-)</td>
<td>106445</td>
</tr>
<tr>
<td>Cumene</td>
<td>98828</td>
</tr>
<tr>
<td>Dibromoethane (1,2) (ethylene dibromide)</td>
<td>106934</td>
</tr>
<tr>
<td>Dichloroethane (1,2)</td>
<td>107062</td>
</tr>
<tr>
<td>Diethanolamine</td>
<td>111422</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>100414</td>
</tr>
<tr>
<td>Ethylene glycol</td>
<td>107211</td>
</tr>
<tr>
<td>Hexane</td>
<td>110543</td>
</tr>
<tr>
<td>Methanol</td>
<td>67561</td>
</tr>
<tr>
<td>Methyl isobutyl ketone (hexone)</td>
<td>108101</td>
</tr>
<tr>
<td>Methyl tert butyl ether</td>
<td>1634044</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>91203</td>
</tr>
<tr>
<td>Phenol</td>
<td>108952</td>
</tr>
<tr>
<td>Toluene</td>
<td>108883</td>
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<tr>
<td>Trimethylpentane (2,2,4)</td>
<td>540841</td>
</tr>
<tr>
<td>Xylene (mixed isomers²)</td>
<td>1330207</td>
</tr>
<tr>
<td>xylene (m-)</td>
<td>108383</td>
</tr>
<tr>
<td>xylene (o-)</td>
<td>95476</td>
</tr>
<tr>
<td>xylene (p-)</td>
<td>106423</td>
</tr>
</tbody>
</table>
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**

<table>
<thead>
<tr>
<th>Standard&lt;sup&gt;a&lt;/sup&gt;</th>
<th>Phase</th>
<th>Leak definition (parts per million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.163 (pumps)</td>
<td>I</td>
<td>10,000</td>
</tr>
<tr>
<td></td>
<td>II</td>
<td>5,000</td>
</tr>
<tr>
<td></td>
<td>III</td>
<td>2,000</td>
</tr>
<tr>
<td>§63.168 (valves)</td>
<td>I</td>
<td>10,000</td>
</tr>
<tr>
<td></td>
<td>II</td>
<td>1,000</td>
</tr>
<tr>
<td></td>
<td>III</td>
<td>1,000</td>
</tr>
</tbody>
</table>

<sup>a</sup>Subpart 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<sup>a</sup>**

<table>
<thead>
<tr>
<th>Reference (section of subpart H of this part)</th>
<th>Description</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>63.181(a)</td>
<td>Recordkeeping system requirements</td>
<td>Except for §§63.181(b)(2)(iii) and 63.181(b)(9).</td>
</tr>
<tr>
<td>63.181(b)</td>
<td>Records required for process unit equipment</td>
<td>Except for §§63.181(b)(2)(iii) and 63.181(b)(9).</td>
</tr>
<tr>
<td>63.181(c)</td>
<td>Visual inspection documentation</td>
<td>Except for §§63.181(b)(2)(iii) and 63.181(b)(9).</td>
</tr>
<tr>
<td>63.181(d)</td>
<td>Leak detection record requirements</td>
<td>Except for §63.181(d)(8).</td>
</tr>
<tr>
<td>63.181(e)</td>
<td>Compliance requirements for pressure tests for batch product process equipment trains</td>
<td>This subsection does not apply to subpart CC.</td>
</tr>
<tr>
<td>63.181(f)</td>
<td>Compressor compliance test records.</td>
<td></td>
</tr>
<tr>
<td>63.181(g)</td>
<td>Closed-vent systems and control device record requirements.</td>
<td></td>
</tr>
<tr>
<td>63.181(h)</td>
<td>Process unit quality improvement program records.</td>
<td></td>
</tr>
<tr>
<td>63.181(i)</td>
<td>Heavy liquid service determination record.</td>
<td></td>
</tr>
<tr>
<td>63.181(j)</td>
<td>Equipment identification record.</td>
<td></td>
</tr>
<tr>
<td>63.181(k)</td>
<td>Enclosed-vented process unit emission limitation record requirements.</td>
<td></td>
</tr>
<tr>
<td>Reference (section of subpart H of this part)</td>
<td>Description</td>
<td>Comment</td>
</tr>
<tr>
<td>---------------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------</td>
</tr>
<tr>
<td>63.182(a)</td>
<td>Reports.</td>
<td></td>
</tr>
<tr>
<td>63.182(b)</td>
<td>Initial notification report requirements.</td>
<td>Not required.</td>
</tr>
<tr>
<td>63.182(c)</td>
<td>Notification of compliance status report</td>
<td>Except in §63.182(c); change &quot;within 90 days of the compliance dates&quot; to &quot;within 150 days of the compliance dates&quot;; except in §§63.182(c)(2) and (c)(4).</td>
</tr>
<tr>
<td>63.182(d)</td>
<td>Periodic report</td>
<td>Except for §§63.182(d)(2)(vii), (d)(2)(viii), and (d)(3).</td>
</tr>
</tbody>
</table>

*This 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*

<table>
<thead>
<tr>
<th>Reference (section of subpart R)</th>
<th>Description</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>63.428(b) or (k)</td>
<td>Records of test results for each gasoline cargo tank loaded at the facility</td>
<td></td>
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<tr>
<td>63.428(c)</td>
<td>Continuous monitoring data recordkeeping requirements</td>
<td></td>
</tr>
<tr>
<td>63.428(g)(1)</td>
<td>Semiannual report loading rack information</td>
<td>Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.</td>
</tr>
<tr>
<td>63.428(h)(1) through (h)(3)</td>
<td>Excess emissions report loading rack information</td>
<td>Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.</td>
</tr>
</tbody>
</table>

*This 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*

<table>
<thead>
<tr>
<th>Reference (section of subpart Y)</th>
<th>Description</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>63.562(e)(2)</td>
<td>Operation and maintenance plan for control equipment and monitoring equipment</td>
<td></td>
</tr>
<tr>
<td>63.565(a)</td>
<td>Performance test/site test plan</td>
<td>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.</td>
</tr>
<tr>
<td>63.565(b)</td>
<td>Performance test data requirements</td>
<td></td>
</tr>
<tr>
<td>63.567(a)</td>
<td>General Provisions (subpart A) applicability</td>
<td></td>
</tr>
<tr>
<td>63.567(c)</td>
<td>Request for extension of compliance</td>
<td></td>
</tr>
<tr>
<td>63.567(d)</td>
<td>Flare recordkeeping requirements</td>
<td></td>
</tr>
</tbody>
</table>
### Reference (section of subpart Y) Description Comment

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**

<table>
<thead>
<tr>
<th>Reference</th>
<th>Applies to subpart CC</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>63.1(a)(1)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.1(a)(2)</td>
<td>Yes</td>
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<tr>
<td>63.1(a)(3)</td>
<td>Yes</td>
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<td>63.1(a)(4)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.1(a)(5)</td>
<td>No</td>
<td>Reserved.</td>
</tr>
<tr>
<td>63.1(a)(6)</td>
<td>Yes</td>
<td>Except the correct mail drop (MD) number is C404-04.</td>
</tr>
<tr>
<td>63.1(a)(7)-63.1(a)(9)</td>
<td>No</td>
<td>Reserved.</td>
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<td>63.1(a)(10)</td>
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<tr>
<td>63.1(a)(11)</td>
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<td>63.1(a)(12)</td>
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<td>63.1(b)(1)</td>
<td>Yes</td>
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<td>63.1(b)(2)</td>
<td>No</td>
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<td>63.1(b)(3)</td>
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<td>63.1(c)(1)</td>
<td>Yes</td>
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<tr>
<td>63.1(c)(2)</td>
<td>No</td>
<td>Area sources are not subject to subpart CC.</td>
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<tr>
<td>63.1(c)(3)-63.1(c)(4)</td>
<td>No</td>
<td>Reserved.</td>
</tr>
<tr>
<td>63.1(c)(5)</td>
<td>Yes</td>
<td>Except that sources are not required to submit notifications overridden by this table.</td>
</tr>
<tr>
<td>Reference</td>
<td>Applies to subpart CC</td>
<td>Comment</td>
</tr>
<tr>
<td>-----------</td>
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</tr>
<tr>
<td>63.1(d)</td>
<td>No</td>
<td>Reserved.</td>
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<tr>
<td>63.1(e)</td>
<td>No</td>
<td>No CAA section 112(j) standard applies to the affected sources under subpart CC.</td>
</tr>
<tr>
<td>63.2</td>
<td>Yes</td>
<td>§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.</td>
</tr>
<tr>
<td>63.3</td>
<td>Yes</td>
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<td>63.4(a)(1)-63.4(a)(2)</td>
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<td>63.4(a)(3)-63.4(a)(5)</td>
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<td>63.4(b)</td>
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<td>63.4(c)</td>
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<td>63.5(a)</td>
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<td>63.5(b)(1)</td>
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<td>63.5(b)(2)</td>
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<td>63.5(b)(3)</td>
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<td>63.5(b)(4)</td>
<td>Yes</td>
<td>Except the cross-reference to §63.9(b) is changed to §63.9(b)(4) and (5). Subpart CC overrides §63.9(b)(2).</td>
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<td>63.5(b)(5)</td>
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<td>63.5(b)(6)</td>
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<td>63.5(c)</td>
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<td>Reserved.</td>
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<tr>
<td>63.5(d)(1)(i)</td>
<td>Yes</td>
<td>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.</td>
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<tr>
<td>63.5(d)(1)(ii)</td>
<td>Yes</td>
<td>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.</td>
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<td>63.5(d)(1)(iii)</td>
<td>No</td>
<td>Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.</td>
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<td>63.5(d)(2)</td>
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<td>63.5(d)(3)</td>
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<td>63.5(d)(4)</td>
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<td>63.5(e)</td>
<td>Yes</td>
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<td>63.5(f)</td>
<td>Yes</td>
<td>Except that the cross-reference in §63.5(f)(2) to §63.9(b)(2) does not apply.</td>
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<td>63.6(a)</td>
<td>Yes</td>
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<td>63.6(b)(1)-63.6(b)(5)</td>
<td>No</td>
<td>Subpart CC specifies compliance dates and notifications for sources subject to subpart CC.</td>
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<td>63.6(b)(6)</td>
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<td>63.6(c)(1)-63.6(c)(2)</td>
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<td>§63.640 of subpart CC specifies the compliance date.</td>
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<td>63.6(c)(3)-63.6(c)(4)</td>
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<td>63.6(d)</td>
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<td>63.6(e)(1)(i) and (ii)</td>
<td>No</td>
<td>See §63.642(n) for general duty requirement.</td>
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<td>63.6(e)(1)(iii)</td>
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<td>63.6(e)(2)</td>
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<td>63.6(e)(3)(i)</td>
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<td>63.6(e)(3)(ii)</td>
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<td>63.6(e)(3)(iii)-63.6(e)(3)(ix)</td>
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<td>63.6(f)(1)</td>
<td>No</td>
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<td>63.6(f)(2)</td>
<td>Yes</td>
<td>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.</td>
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<td>63.6(f)(3)</td>
<td>Yes</td>
<td>Except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.642(n) and performance test results may be written or electronic.</td>
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<td>63.6(g)</td>
<td>Yes</td>
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<td>63.6(h)(1)</td>
<td>No</td>
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<td>63.6(h)(2)</td>
<td>Yes</td>
<td>Except §63.6(h)(2)(ii), which is reserved.</td>
</tr>
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<td>63.6(h)(3)</td>
<td>No</td>
<td>Reserved.</td>
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<td>63.6(h)(4)</td>
<td>No</td>
<td>Notification of visible emission test not required in subpart CC.</td>
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<tr>
<td>63.6(h)(5)</td>
<td>No</td>
<td>Visible emission requirements and timing is specified in §63.645(i) of subpart CC.</td>
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<td>63.6(h)(6)</td>
<td>Yes</td>
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<td>63.6(h)(7)</td>
<td>No</td>
<td>Subpart CC does not require opacity standards.</td>
</tr>
<tr>
<td>63.6(h)(8)</td>
<td>Yes</td>
<td>Except performance test results may be written or electronic.</td>
</tr>
<tr>
<td>63.6(h)(9)</td>
<td>No</td>
<td>Subpart CC does not require opacity standards.</td>
</tr>
<tr>
<td>63.6(i)</td>
<td>Yes</td>
<td>Except §63.6(i)(15), which is reserved.</td>
</tr>
<tr>
<td>63.6(j)</td>
<td>Yes</td>
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<tr>
<td>63.7(a)(1)</td>
<td>Yes</td>
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<tr>
<td>63.7(a)(2)</td>
<td>Yes</td>
<td>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), unless they are required to be submitted electronically in accordance with §63.655(h)(9). Test results required to be submitted electronically must be submitted by the date the Notification of Compliance Status report is submitted.</td>
</tr>
<tr>
<td>63.7(a)(3)</td>
<td>Yes</td>
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<tr>
<td>Reference</td>
<td>Applies to subpart CC</td>
<td>Comment</td>
</tr>
<tr>
<td>-----------</td>
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<tr>
<td>63.7(a)(4)</td>
<td>Yes</td>
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<tr>
<td>63.7(b)</td>
<td>Yes</td>
<td>Except this subpart requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.</td>
</tr>
<tr>
<td>63.7(c)</td>
<td>No</td>
<td>Subpart CC does not require a site-specific test plan.</td>
</tr>
<tr>
<td>63.7(d)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.7(e)(1)</td>
<td>No</td>
<td>See §63.642(d)(3).</td>
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<tr>
<td>63.7(e)(2)-63.7(e)(4)</td>
<td>Yes</td>
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<tr>
<td>63.7(f)</td>
<td>Yes</td>
<td>Except that additional notification or approval is not required for alternatives directly specified in Subpart CC.</td>
</tr>
<tr>
<td>63.7(g)</td>
<td>No</td>
<td>Performance test reporting specified in §63.655(f).</td>
</tr>
<tr>
<td>63.7(h)(1)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.7(h)(2)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.7(h)(3)</td>
<td>Yes</td>
<td>Yes, except site-specific test plans shall not be required, and where §63.7(h)(3)(i) specifies waiver submittal date, the date shall be 90 days prior to the Notification of Compliance Status report in §63.655(f).</td>
</tr>
<tr>
<td>63.7(h)(4)(i)</td>
<td>Yes</td>
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<tr>
<td>63.7(h)(4)(ii)</td>
<td>No</td>
<td>Site-specific test plans are not required in subpart CC.</td>
</tr>
<tr>
<td>63.7(h)(4)(iii) and (iv)</td>
<td>Yes</td>
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<td>63.7(h)(5)</td>
<td>Yes</td>
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<tr>
<td>63.8(a)(1) and (2)</td>
<td>Yes.</td>
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<tr>
<td>63.8(a)(3)</td>
<td>No</td>
<td>Reserved.</td>
</tr>
<tr>
<td>63.8(a)(4)</td>
<td>Yes</td>
<td>Except that for a flare complying with §63.670, the cross-reference to §63.11 in this paragraph does not include §63.11(b).</td>
</tr>
<tr>
<td>63.8(b)</td>
<td>Yes</td>
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<td>63.8(c)(1)</td>
<td>Yes</td>
<td>Except §63.8(c)(1)(i) and (iii).</td>
</tr>
<tr>
<td>63.8(c)(1)(i)</td>
<td>No</td>
<td>See §63.642(n).</td>
</tr>
<tr>
<td>63.8(c)(1)(iii)</td>
<td>No.</td>
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<tr>
<td>63.8(c)(2)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.8(c)(3)</td>
<td>Yes</td>
<td>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.</td>
</tr>
<tr>
<td>63.8(c)(4)</td>
<td>Yes</td>
<td>Except that for sources other than flares, this subpart specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is &quot;once every hour&quot; rather than &quot;for each successive 15-minute period.&quot;</td>
</tr>
<tr>
<td>Reference</td>
<td>Applies to subpart CC</td>
<td>Comment</td>
</tr>
<tr>
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<tr>
<td>63.8(c)(5)-63.8(c)(8)</td>
<td>No</td>
<td>This subpart specifies continuous monitoring system requirements.</td>
</tr>
<tr>
<td>63.8(d)</td>
<td>No</td>
<td>This subpart specifies quality control procedures for continuous monitoring systems.</td>
</tr>
<tr>
<td>63.8(e)</td>
<td>Yes</td>
<td>Except that results are to be submitted electronically if required by §63.655(h)(9).</td>
</tr>
<tr>
<td>63.8(f)(1)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.8(f)(2)</td>
<td>Yes</td>
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<td>63.8(f)(3)</td>
<td>Yes</td>
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<tr>
<td>63.8(f)(4)(i)</td>
<td>No</td>
<td>Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.</td>
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<tr>
<td>63.8(f)(4)(ii)</td>
<td>Yes</td>
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<tr>
<td>63.8(f)(4)(iii)</td>
<td>No</td>
<td>Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.</td>
</tr>
<tr>
<td>63.8(f)(5)</td>
<td>Yes</td>
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<tr>
<td>63.8(f)(6)</td>
<td>No</td>
<td>Subpart CC does not require continuous emission monitors.</td>
</tr>
<tr>
<td>63.8(g)</td>
<td>No</td>
<td>This subpart specifies data reduction procedures in §§63.655(i)(3) and 63.671(d).</td>
</tr>
<tr>
<td>63.9(a)</td>
<td>Yes</td>
<td>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).</td>
</tr>
<tr>
<td>63.9(b)(1)</td>
<td>Yes</td>
<td>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).</td>
</tr>
<tr>
<td>63.9(b)(2)</td>
<td>No</td>
<td>A separate Initial Notification report is not required under subpart CC.</td>
</tr>
<tr>
<td>63.9(b)(3)</td>
<td>No</td>
<td>Reserved.</td>
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<td>63.9(b)(4)</td>
<td>Yes</td>
<td>Except for subparagraphs §63.9(b)(4)(ii) through (iv), which are reserved.</td>
</tr>
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<td>63.9(b)(5)</td>
<td>Yes</td>
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<td>63.9(c)</td>
<td>Yes</td>
<td></td>
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<tr>
<td>63.9(d)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.9(e)</td>
<td>No</td>
<td>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.</td>
</tr>
<tr>
<td>63.9(f)</td>
<td>No</td>
<td>Subpart CC does not require advanced notification of visible emissions test.</td>
</tr>
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<td>63.9(g)</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>63.9(h)</td>
<td>No</td>
<td>Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.</td>
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<tr>
<td>63.9(i)</td>
<td>Yes</td>
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<tr>
<td>63.9(j)</td>
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<td>63.10(a)</td>
<td>Yes</td>
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<td>63.10(b)(1)</td>
<td>No</td>
<td>§63.655(i) of subpart CC specifies record retention requirements.</td>
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<td>63.10(b)(2)(i)</td>
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<td>63.10(b)(2)(ii)</td>
<td>No</td>
<td>§63.655(i) specifies the records that must be kept.</td>
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<td>63.10(b)(2)(iii)</td>
<td>No</td>
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<td>Comment</td>
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<td>63.10(b)(2)(iv)</td>
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<td>63.10(b)(2)(v)</td>
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<td>63.10(b)(2)(vi)</td>
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<td>63.10(b)(2)(vii)</td>
<td>No</td>
<td>§63.655(i) specifies records to be kept for parameters measured with continuous monitors.</td>
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<td>63.10(b)(2)(viii)</td>
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<td>63.10(b)(2)(ix)</td>
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<td>63.10(b)(2)(x)</td>
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<td>63.10(b)(2)(xii)</td>
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<td>63.10(c)(8)</td>
<td>Yes</td>
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<td>63.10(c)(9)</td>
<td>No</td>
<td>Reserved.</td>
</tr>
<tr>
<td>63.10(c)(10)-</td>
<td>No</td>
<td>§63.655(i) specifies the records that must be kept.</td>
</tr>
<tr>
<td>63.10(c)(11)</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>63.10(c)(12)-</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>63.10(c)(15)</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>63.10(d)(1)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.10(d)(2)</td>
<td>No</td>
<td>Although §63.655(f) specifies performance test reporting, EPA may approve other timeframes for submittal of performance test data.</td>
</tr>
<tr>
<td>63.10(d)(3)</td>
<td>No</td>
<td>Results of visible emissions test are included in Compliance Status Report as specified in §63.655(f).</td>
</tr>
<tr>
<td>63.10(d)(4)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.10(d)(5)</td>
<td>No</td>
<td>§63.655(g) specifies the reporting requirements.</td>
</tr>
<tr>
<td>63.10(e)</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>63.10(f)</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>63.11</td>
<td>Yes</td>
<td>Except that flares complying with §63.670 are not subject to the requirements of §63.11(b).</td>
</tr>
<tr>
<td>63.12-63.16</td>
<td>Yes</td>
<td></td>
</tr>
</tbody>
</table>

*Wherever 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.*

[60 FR 43260, Aug. 18, 1995, as amended at 83 FR 60713, Nov. 26, 2018]
### TABLE 7—FRACTION MEASURED (FM), FRACTION EMITTED (FE), AND FRACTION REMOVED (FR) FOR HAP COMPOUNDS IN WASTEWATER STREAMS

<table>
<thead>
<tr>
<th>Chemical name</th>
<th>CAS No.</th>
<th>FM</th>
<th>FE</th>
<th>Fr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benzene</td>
<td>71432</td>
<td>1.00</td>
<td>0.80</td>
<td>0.99</td>
</tr>
<tr>
<td>Biphenyl</td>
<td>92524</td>
<td>0.86</td>
<td>0.45</td>
<td>0.99</td>
</tr>
<tr>
<td>Butadiene (1,3)</td>
<td>106990</td>
<td>1.00</td>
<td>0.98</td>
<td>0.99</td>
</tr>
<tr>
<td>Carbon disulfide</td>
<td>75150</td>
<td>1.00</td>
<td>0.92</td>
<td>0.99</td>
</tr>
<tr>
<td>Cumene</td>
<td>98828</td>
<td>1.00</td>
<td>0.88</td>
<td>0.99</td>
</tr>
<tr>
<td>Dichloroethane (1,2-) (Ethylene dichloride)</td>
<td>107062</td>
<td>1.00</td>
<td>0.64</td>
<td>0.99</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>100414</td>
<td>1.00</td>
<td>0.83</td>
<td>0.99</td>
</tr>
<tr>
<td>Hexane</td>
<td>110543</td>
<td>1.00</td>
<td>1.00</td>
<td>0.99</td>
</tr>
<tr>
<td>Methanol</td>
<td>67561</td>
<td>0.85</td>
<td>0.17</td>
<td>0.31</td>
</tr>
<tr>
<td>Methyl isobutyl ketone (hexone)</td>
<td>108101</td>
<td>0.98</td>
<td>0.53</td>
<td>0.99</td>
</tr>
<tr>
<td>Methyl tert butyl ether</td>
<td>1634044</td>
<td>1.00</td>
<td>0.57</td>
<td>0.99</td>
</tr>
<tr>
<td>Naphthalene</td>
<td>91203</td>
<td>0.99</td>
<td>0.51</td>
<td>0.99</td>
</tr>
<tr>
<td>Trimethylpentane (2,2,4)</td>
<td>540841</td>
<td>1.00</td>
<td>1.00</td>
<td>0.99</td>
</tr>
<tr>
<td>xylene (m-)</td>
<td>108383</td>
<td>1.00</td>
<td>0.82</td>
<td>0.99</td>
</tr>
<tr>
<td>xylene (o-)</td>
<td>95476</td>
<td>1.00</td>
<td>0.79</td>
<td>0.99</td>
</tr>
<tr>
<td>xylene (p-)</td>
<td>106423</td>
<td>1.00</td>
<td>0.82</td>
<td>0.99</td>
</tr>
</tbody>
</table>

*CAS 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

<table>
<thead>
<tr>
<th>Performance level Leaking valves* (%</th>
<th>Valve monitoring frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>≥4</td>
<td>Monthly or QIP. b</td>
</tr>
<tr>
<td>&lt;4</td>
<td>Quarterly.</td>
</tr>
<tr>
<td>&lt;3</td>
<td>Semiannual.</td>
</tr>
<tr>
<td>&lt;2</td>
<td>Annual.</td>
</tr>
</tbody>
</table>

*Percent 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

<table>
<thead>
<tr>
<th>Performance level Leaking valves* (%</th>
<th>Valve monitoring frequency under §63.649 alternative</th>
</tr>
</thead>
<tbody>
<tr>
<td>≥5</td>
<td>Monthly or QIP. b</td>
</tr>
<tr>
<td>Performance level</td>
<td>Valve monitoring frequency under §63.649 alternative</td>
</tr>
<tr>
<td>-------------------</td>
<td>-----------------------------------------------</td>
</tr>
<tr>
<td>Leaking valves(^a) (%)</td>
<td></td>
</tr>
<tr>
<td>&lt;5</td>
<td>Quarterly.</td>
</tr>
<tr>
<td>&lt;4</td>
<td>Semiannual.</td>
</tr>
<tr>
<td>&lt;3</td>
<td>Annual.</td>
</tr>
</tbody>
</table>

\(^a\)Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

\(^b\)QIP = 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**

<table>
<thead>
<tr>
<th>Control device</th>
<th>Parameters to be monitored(^b)</th>
<th>Recordkeeping and reporting requirements for monitored parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal incinerator</td>
<td>Firebox temperature(^h)</td>
<td>1. Continuous records(^c).</td>
</tr>
<tr>
<td></td>
<td>(63.644(a)(1)(i))</td>
<td>2. Record and report the firebox temperature averaged over the full period of the performance test—NCS(^d).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3. Record the daily average firebox temperature for each operating day(^e).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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).</td>
</tr>
<tr>
<td>Catalytic incinerator</td>
<td>Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii))</td>
<td>1. Continuous records(^c).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day(^e).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR(^g).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6. Report all operating days when insufficient monitoring data are collected(^f).</td>
</tr>
<tr>
<td>Control device</td>
<td>Parameters to be monitored&lt;sup&gt;a&lt;/sup&gt;</td>
<td>Recordkeeping and reporting requirements for monitored parameters</td>
</tr>
<tr>
<td>---------------</td>
<td>--------------------------------------</td>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td>Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is not introduced into the flame zone&lt;sup&gt;h&lt;/sup&gt;</td>
<td>Firebox temperature&lt;sup&gt;b&lt;/sup&gt; (63.644(a)(4))</td>
<td>1. Continuous records&lt;sup&gt;c&lt;/sup&gt;.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. Record and report the firebox temperature averaged over the full period of the performance test—NCS&lt;sup&gt;d&lt;/sup&gt;.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3. Record the daily average firebox temperature for each operating day&lt;sup&gt;e&lt;/sup&gt;.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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&lt;sup&gt;f&lt;/sup&gt;—PR&lt;sup&gt;g&lt;/sup&gt;.</td>
</tr>
<tr>
<td>Flare (if meeting the requirements of §§63.643 and 63.644)</td>
<td>Presence of a flame at the pilot light (63.644(a)(2))</td>
<td>1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS&lt;sup&gt;d&lt;/sup&gt;.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.</td>
</tr>
<tr>
<td>Flare (if meeting the requirements of §§63.670 and 63.671)</td>
<td>The parameters specified in §63.670</td>
<td>1. Records as specified in §63.655(i)(9).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. Report information as specified in §63.655(g)(11)—PR&lt;sup&gt;g&lt;/sup&gt;.</td>
</tr>
<tr>
<td>All control devices</td>
<td>Presence of flow diverted to the atmosphere from the control device (§63.644(c)(1)) or Monthly inspections of sealed valves (§63.644(c)(2))</td>
<td>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&lt;sup&gt;g&lt;/sup&gt;.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1. Records that monthly inspections were performed.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR&lt;sup&gt;g&lt;/sup&gt;.</td>
</tr>
</tbody>
</table>

<sup>a</sup>Regulatory citations are listed in parentheses.

<sup>b</sup>Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

<sup>c</sup>“Continuous records” is defined in §63.641.

<sup>d</sup>NCS = Notification of Compliance Status Report described in §63.655.
The 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.

When 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.

PR = Periodic Reports described in §63.655(g).

No 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.

Process 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**

<table>
<thead>
<tr>
<th>If the construction/reconstruction date is . . .</th>
<th>Then the owner or operator must comply with . . .</th>
<th>And the owner or operator must achieve compliance . . .</th>
<th>Except as provided in . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) After June 30, 2014</td>
<td>(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</td>
<td>Upon initial startup</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(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</td>
<td>Upon initial startup or February 1, 2016, whichever is later</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td>(2) After September 4, 2007 but on or before June 30, 2014</td>
<td>(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</td>
<td>Upon initial startup</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(ii) Requirements for new sources in §63.654</td>
<td>Upon initial startup or October 28, 2009, whichever is later</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)</td>
<td>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</td>
<td>§§63.640(k), (l) and (m) and 63.660(d).</td>
</tr>
<tr>
<td></td>
<td>(iv) Requirements for existing sources in §63.643(c)</td>
<td>On or before December 26, 2018</td>
<td>§§63.640(k), (l) and (m) and 63.643(d).</td>
</tr>
<tr>
<td></td>
<td>(v) Requirements for existing sources in §63.658</td>
<td>On or before January 30, 2018</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(vi) Requirements for existing sources in §§63.649 (j)(3), (6) and (7) and §63.657</td>
<td>On or before January 30, 2019</td>
<td>$63.640(k), (l) and (m).</td>
</tr>
<tr>
<td>If the construction/reconstruction date is . . .</td>
<td>Then the owner or operator must comply with . . .</td>
<td>And the owner or operator must achieve compliance . . .</td>
<td>Except as provided in . . .</td>
</tr>
<tr>
<td>------------------------------------------------</td>
<td>-------------------------------------------------</td>
<td>-------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>(3) After July 14, 1994 but on or before September 4, 2007</td>
<td>(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</td>
<td>Upon initial startup or August 18, 1995, whichever is later</td>
<td>§63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(ii) Requirements for existing sources in §63.654</td>
<td>On or before October 29, 2012</td>
<td>§63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)</td>
<td>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</td>
<td>§§63.640(k), (l) and (m) and 63.660(d).</td>
</tr>
<tr>
<td></td>
<td>(iv) Requirements for existing sources in §63.643(c)</td>
<td>On or before December 26, 2018</td>
<td>§§63.640(k), (l) and (m) and 63.643(d).</td>
</tr>
<tr>
<td></td>
<td>(v) Requirements for existing sources in §63.658</td>
<td>On or before January 30, 2018</td>
<td>§63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(vi) Requirements for existing sources in §§63.648(j)(3), (6) and (7) and 63.657</td>
<td>On or before January 30, 2019</td>
<td>§63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(vii) Requirements in §63.642(n)</td>
<td>Upon initial startup or February 1, 2016, whichever is later</td>
<td></td>
</tr>
<tr>
<td>(4) On or before July 14, 1994</td>
<td>(i) Requirements for existing sources in §§63.648(a) through (i) and (j)(1) and (2); and 63.649, 63.655 and 63.656</td>
<td>(A) On or before August 18, 1998</td>
<td>(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).</td>
</tr>
<tr>
<td></td>
<td>(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</td>
<td>(A) On or before August 18, 1998</td>
<td>(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).</td>
</tr>
<tr>
<td></td>
<td>(iii) Requirements for existing sources in either §63.646 or §63.660 or, if applicable, §63.640(n)</td>
<td>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</td>
<td>§§63.640(k), (l) and (m) and 63.660(d).</td>
</tr>
<tr>
<td></td>
<td>(iv) Requirements for existing sources in §63.654</td>
<td>On or before October 29, 2012</td>
<td>§63.640(k), (l) and (m).</td>
</tr>
<tr>
<td></td>
<td>(v) Requirements for existing sources in §63.643(c)</td>
<td>On or before December 26, 2018</td>
<td>§§63.640(k), (l) and (m) and 63.643(d).</td>
</tr>
</tbody>
</table>
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 . . .

| (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 §63.642 (n) | Upon initial startup or February 1, 2016, whichever is later |

[60 FR 43260, Aug. 18, 1995, as amended at 83 FR 60713, Nov. 26, 2018]

**TABLE 12—INDIVIDUAL COMPONENT PROPERTIES**

<table>
<thead>
<tr>
<th>Component</th>
<th>Molecular formula</th>
<th>MWi (pounds per pound-mole)</th>
<th>CMNi (mole per mole)</th>
<th>NHVi (British thermal units per standard cubic foot)</th>
<th>LFLi (volume %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acetylene</td>
<td>C₂H₂</td>
<td>26.04</td>
<td>2</td>
<td>1,404</td>
<td>2.5</td>
</tr>
<tr>
<td>Benzene</td>
<td>C₆H₆</td>
<td>78.11</td>
<td>6</td>
<td>3,591</td>
<td>1.3</td>
</tr>
<tr>
<td>1,2-Butadiene</td>
<td>C₄H₆</td>
<td>54.09</td>
<td>4</td>
<td>2,794</td>
<td>2.0</td>
</tr>
<tr>
<td>1,3-Butadiene</td>
<td>C₆H₆</td>
<td>54.09</td>
<td>4</td>
<td>2,690</td>
<td>2.0</td>
</tr>
<tr>
<td>iso-Butane</td>
<td>C₄H₁₀</td>
<td>58.12</td>
<td>4</td>
<td>2,957</td>
<td>1.8</td>
</tr>
<tr>
<td>n-Butane</td>
<td>C₄H₁₀</td>
<td>58.12</td>
<td>4</td>
<td>2,968</td>
<td>1.8</td>
</tr>
<tr>
<td>cis-Butene</td>
<td>C₄H₈</td>
<td>56.11</td>
<td>4</td>
<td>2,830</td>
<td>1.6</td>
</tr>
<tr>
<td>iso-Butene</td>
<td>C₄H₈</td>
<td>56.11</td>
<td>4</td>
<td>2,928</td>
<td>1.8</td>
</tr>
<tr>
<td>trans-Butene</td>
<td>C₄H₈</td>
<td>56.11</td>
<td>4</td>
<td>2,826</td>
<td>1.7</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>CO₂</td>
<td>44.01</td>
<td>1</td>
<td>0</td>
<td>∞</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>CO</td>
<td>28.01</td>
<td>1</td>
<td>316</td>
<td>12.5</td>
</tr>
<tr>
<td>Cyclopropane</td>
<td>C₃H₆</td>
<td>42.08</td>
<td>3</td>
<td>2,185</td>
<td>2.4</td>
</tr>
<tr>
<td>Ethane</td>
<td>C₂H₆</td>
<td>30.07</td>
<td>2</td>
<td>1,595</td>
<td>3.0</td>
</tr>
<tr>
<td>Ethylene</td>
<td>C₂H₄</td>
<td>28.05</td>
<td>2</td>
<td>1,477</td>
<td>2.7</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>H₂</td>
<td>2.02</td>
<td>0</td>
<td>1,212a</td>
<td>4.0</td>
</tr>
<tr>
<td>Hydrogen Sulfide</td>
<td>H₂S</td>
<td>34.08</td>
<td>0</td>
<td>587</td>
<td>4.0</td>
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<tr>
<td>Methane</td>
<td>CH₄</td>
<td>16.04</td>
<td>1</td>
<td>896</td>
<td>5.0</td>
</tr>
<tr>
<td>Methyl-Acetylene</td>
<td>C₃H₄</td>
<td>40.06</td>
<td>3</td>
<td>2,088</td>
<td>1.7</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>N₂</td>
<td>28.01</td>
<td>0</td>
<td>0</td>
<td>∞</td>
</tr>
<tr>
<td>Oxygen</td>
<td>O₂</td>
<td>32.00</td>
<td>0</td>
<td>0</td>
<td>∞</td>
</tr>
<tr>
<td>Pentane+ (C5+)</td>
<td>C₅H₁₂</td>
<td>72.15</td>
<td>5</td>
<td>3,655</td>
<td>1.4</td>
</tr>
<tr>
<td>Propadiene</td>
<td>C₃H₄</td>
<td>40.06</td>
<td>3</td>
<td>2,066</td>
<td>2.16</td>
</tr>
<tr>
<td>Component</td>
<td>Molecular formula</td>
<td>MW&lt;sub&gt;i&lt;/sub&gt; (pounds per pound-mole)</td>
<td>CMNi (mole per mole)</td>
<td>NHV&lt;sub&gt;i&lt;/sub&gt; (British thermal units per standard cubic foot)</td>
<td>LFL&lt;sub&gt;i&lt;/sub&gt; (volume %)</td>
</tr>
<tr>
<td>---------------</td>
<td>-------------------</td>
<td>---------------------------------------</td>
<td>----------------------</td>
<td>-------------------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>Propane</td>
<td>C&lt;sub&gt;3&lt;/sub&gt;H&lt;sub&gt;8&lt;/sub&gt;</td>
<td>44.10</td>
<td>3</td>
<td>2,281</td>
<td>2.1</td>
</tr>
<tr>
<td>Propylene</td>
<td>C&lt;sub&gt;3&lt;/sub&gt;H&lt;sub&gt;6&lt;/sub&gt;</td>
<td>42.08</td>
<td>3</td>
<td>2,150</td>
<td>2.4</td>
</tr>
<tr>
<td>Water</td>
<td>H&lt;sub&gt;2&lt;/sub&gt;O</td>
<td>18.02</td>
<td>0</td>
<td>0</td>
<td>∞</td>
</tr>
</tbody>
</table>

The 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**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Minimum accuracy requirements</th>
<th>Calibration requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature</td>
<td>±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater</td>
<td>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.</td>
</tr>
<tr>
<td>Flow Rate for All Flows Other Than Flare Vent Gas</td>
<td>±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</td>
<td>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. 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.</td>
</tr>
<tr>
<td>Flow Rate for Flare Vent Gas</td>
<td>±5 percent over the normal range measured for mass flow</td>
<td>±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</td>
</tr>
<tr>
<td>Flow Rate</td>
<td>±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second)</td>
<td>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. 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.</td>
</tr>
<tr>
<td>Parameter</td>
<td>Minimum accuracy requirements</td>
<td>Calibration requirements</td>
</tr>
<tr>
<td>-----------</td>
<td>------------------------------</td>
<td>---------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Record the results of each calibration check and inspection.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Pressure</td>
<td>±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Record the results of each calibration check and inspection.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Net Heating Value by Calorimeter</td>
<td>±2 percent of span</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Net Heating Value by Gas Chromatograph</td>
<td>As specified in Performance Specification 9 of 40 CFR part 60, appendix B</td>
<td>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).</td>
</tr>
<tr>
<td>Hydrogen analyzer</td>
<td>±2 percent over the concentration measured or 0.1 volume percent, whichever is greater</td>
<td>Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Where feasible, 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.</td>
</tr>
</tbody>
</table>
PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart XX—Standards of Performance for Bulk Gasoline Terminals

SOURCE: 48 FR 37590, Aug. 18, 1983, unless otherwise noted.

§ 60.500 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is the total of all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks.

(b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, is subject to the provisions of this subpart.

(c) For purposes of this subpart, any replacement of components of an existing facility, described in paragraph (a) of this section, commenced before August 18, 1983 in order to comply with any emission standard adopted by a State or political subdivision thereof will not be considered a reconstruction under the provisions of 40 CFR 60.15.

NOTE: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technologies (BDT). The numerical emission limits in this standard are expressed in terms of total organic compounds. This emission limit reflects the performance of BDT.

§ 60.501 Definitions.

The terms used in this subpart are defined in the Clean Air Act, in § 60.2 of this part, or in this section as follows:

**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.

**Continuous vapor processing system** means a vapor processing system that treats total organic compounds vapors collected from gasoline tank trucks on a demand basis without intermediate accumulation in a vapor holder.

**Existing vapor processing system** means a vapor processing system [capable of achieving emissions to the atmosphere no greater than 80 milligrams of total organic compounds per liter of gasoline loaded], the construction or refurbishment of which was commenced before December 17, 1980, and which was not constructed or refurbished after that date.

**Flare** means a thermal oxidation system using an open (without enclosure) flame.

**Gasoline** means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater which is used as a fuel for internal combustion engines.
Gasoline tank truck means a delivery tank truck used at bulk gasoline terminals which is loading gasoline or which has loaded gasoline on the immediately previous load.

Intermittent vapor processing system means a vapor processing system that employs an intermediate vapor holder to accumulate total organic compounds vapors collected from gasoline tank trucks, and treats the accumulated vapors only during automatically controlled cycles.

Loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tank trucks.

Refurbishment means, with reference to a vapor processing system, replacement of components of, or addition of components to, the system within any 2-year period such that the fixed capital cost of the new components required for such component replacement or addition exceeds 50 percent of the cost of a comparable entirely new system.

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.

Total organic compounds means those compounds measured according to the procedures in § 60.503.

Vapor collection system means any equipment used for containing total organic compounds vapors displaced during the loading of gasoline tank trucks.

Vapor processing system means all equipment used for recovering or oxidizing total organic compounds vapors displaced from the affected facility.

Vapor-tight gasoline tank truck means a gasoline tank truck which has demonstrated within the 12 preceding months that its product delivery tank will sustain a pressure change of not more than 750 pascals (75 mm of water) within 5 minutes after it is pressurized to 4,500 pascals (450 mm of water). This capability is to be demonstrated using the pressure test procedure specified in Method 27.


§ 60.502 Standard for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals.

On and after the date on which § 60.8(a) requires a performance test to be completed, the owner or operator of each bulk gasoline terminal containing an affected facility shall comply with the requirements of this section.

(a) Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

(b) The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in paragraph (c) of this section.

(c) For each affected facility equipped with an existing vapor processing system, the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 80 milligrams of total organic compounds per liter of gasoline loaded.

(d) Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:
(1) The owner or operator shall obtain the vapor tightness documentation described in §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.

(2) The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.

(3)(i) The owner or operator shall cross-check each tank identification number obtained in paragraph (e)(2) of this section with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:

(A) If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or

(B) If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.

(ii) If either the quarterly or semiannual cross-check provided in paragraphs (e)(3)(i) (A) through (B) of this section reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.

(4) The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in paragraph (e)(3) of this section.

(5) The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.

(6) Alternate procedures to those described in paragraphs (e)(1) through (5) of this section for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

(f) The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

(g) The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

(h) The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).

(i) No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 4,500 pascals (450 mm of water).

(j) Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.


§60.503 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). The three-run requirement of §60.8(f) does not apply to this subpart.
(b) Immediately before the performance test required to determine compliance with § 60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal’s vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.

(c) The owner or operator shall determine compliance with the standards in § 60.502 (b) and (c) as follows:

(1) The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.

(2) If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.

(3) The emission rate (E) of total organic compounds shall be computed using the following equation:

\[
E = \sum_{i=1}^{n} \left( \frac{V_{esi} C_{esi}}{L} \right) 10^6
\]

where:

- \(E\) = emission rate of total organic compounds, mg/liter of gasoline loaded.
- \(V_{esi}\) = volume of air-vapor mixture exhausted at each interval “i”, scm.
- \(C_{esi}\) = concentration of total organic compounds at each interval “i”, ppm.
- \(L\) = total volume of gasoline loaded, liters.
- \(n\) = number of testing intervals.
- \(i\) = emission testing interval of 5 minutes.
- \(K\) = density of calibration gas, 1.83 \times 10^6 for propane and 2.41 \times 10^6 for butane, mg/scm.

(4) The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (\(V_{esi}\)) and the corresponding average total organic compounds concentration (\(C_{esi}\)) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.

(5) The following methods shall be used to determine the volume (\(V_{esi}\)) air-vapor mixture exhausted at each interval:

(i) Method 2B shall be used for combustion vapor processing systems.

(ii) Method 2A shall be used for all other vapor processing systems.

(6) Method 25A or 25B shall be used for determining the total organic compounds concentration (\(C_{esi}\)) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.
(7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

(d) The owner or operator shall determine compliance with the standard in § 60.502(h) as follows:

(1) A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.

(2) During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.

(e) The performance test requirements of paragraph (c) of this section do not apply to flares defined in § 60.501 and meeting the requirements in § 60.18(b) through (f). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §§ 60.18(b) through (f) and 60.503(a), (b), and (d).

(f) The owner or operator shall use alternative test methods and procedures in accordance with the alternative test method provisions in § 60.8(b) for flares that do not meet the requirements in § 60.18(b).


§ 60.504  [Reserved]

§ 60.505  Reporting and recordkeeping.

(a) The tank truck vapor tightness documentation required under § 60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.

(b) The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

(1) Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.

(2) Tank owner and address.

(3) Tank identification number.

(4) Testing location.

(5) Date of test.

(6) Tester name and signature.

(7) Witnessing inspector, if any: Name, signature, and affiliation.

(8) Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).

(c) A record of each monthly leak inspection required under § 60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

(1) Date of inspection.
(2) Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).

(3) Leak determination method.

(4) Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).

(5) Inspector name and signature.

(d) The terminal owner or operator shall keep documentation of all notifications required under § 60.502(e)(4) on file at the terminal for at least 2 years.

(e) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraphs (a), (c), and (d) of this section, an owner or operator may comply with the requirements in either paragraph (e)(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 (e)(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 (e)(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 (e)(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 (e)(2) of this section.

(f) The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.


§ 60.506 Reconstruction.

For purposes of this subpart:

(a) The cost of the following frequently replaced components of the affected 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 entirely new facility” under § 60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(b) Under § 60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components (except components specified in § 60.506(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following December 17, 1980. 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.
Indiana Department of Environmental Management  
Office of Air Quality  
Technical Support Document (TSD) for a Part 70 Administrative Operating Permit Renewal

<table>
<thead>
<tr>
<th>Source Description and Location</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Source Name:</strong></td>
</tr>
<tr>
<td><strong>Source Location:</strong></td>
</tr>
<tr>
<td><strong>County:</strong></td>
</tr>
<tr>
<td><strong>SIC Code:</strong></td>
</tr>
<tr>
<td><strong>Administrative Permit Renewal No.:</strong></td>
</tr>
<tr>
<td><strong>Permit Reviewer:</strong></td>
</tr>
</tbody>
</table>

On July 19, 2019, CountryMark Refining and Logistics, LLC submitted an application to the Office of Air Quality (OAQ) requesting to renew its administrative operating permit. OAQ has reviewed the administrative operating permit renewal application from CountryMark Refining and Logistics, LLC relating to the operation of a stationary petroleum refinery. CountryMark Refining and Logistics, LLC was issued its Part 70 Administrative Operating Permit Renewal (T 129-35011-00037) on April 21, 2015.

<table>
<thead>
<tr>
<th>Source Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>This source definition for this source is incorporated into this permit as follows:</td>
</tr>
<tr>
<td>This petroleum refinery and marine vessel loading and unloading river dock terminal consists of two (2) plants:</td>
</tr>
<tr>
<td>(a) Plant 1 is located at 1200 Refinery Road, Mount Vernon, IN 47620; and</td>
</tr>
<tr>
<td>(b) Plant 2 is located at South Mann St. and West Ohio St., Mount Vernon, IN 47620.</td>
</tr>
<tr>
<td>However, these plants are located on one or more adjacent properties, have the same two digit SIC code and a support relationship, and are still under common ownership, therefore they are considered one (1) major source, as defined by 326 IAC 2-7-1(22).</td>
</tr>
<tr>
<td>A Part 70 Operating permits will be issued to Country Mark Refining and Logistics, LLC (129-00003). A separate Administrative Part 70 permit will be issued to Country Mark Refining and Logistics, LLC (129-00037), solely for administrative purposes. This conclusion was initially determined under Significant Permit Modification (129-17940-00003) issued on November 24, 2003.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Existing Approvals</th>
</tr>
</thead>
<tbody>
<tr>
<td>The source was issued Part 70 Administrative Operating Permit Renewal No. T 129-35011-00037 on April 21, 2015. The source has since received the following approval:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Permit Type</th>
<th>Permit Number</th>
<th>Issuance Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>TV AA</td>
<td>129-37206-00037</td>
<td>July 20, 2016</td>
</tr>
<tr>
<td>TV Minor Source Modification</td>
<td>129-41173-00037</td>
<td>June 7, 2019</td>
</tr>
<tr>
<td>TV Significant Permit Modification</td>
<td>129-41303-00037</td>
<td>August 5, 2019</td>
</tr>
</tbody>
</table>
All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

---

**Emission Units and Pollution Control Equipment**

The source consists of the following permitted emission units:

(a) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas. Under 40 CFR 63, Subpart R this is an affected facility. Under 40 CFR 63, Subpart CC this is an affected facility.

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**Insignificant Activities**

The source also consists of the following regulated insignificant activities:

(a) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

1. For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
2. For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
3. For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
4. For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.
5. For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.
6. For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

(A) One (1) fixed roof cone tank, identified as Tank No. 23, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(B) One (1) fixed roof cone tank, identified as Tank No. 27, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(C) One (1) fixed roof cone tank, identified as Tank No. 28, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(D) One (1) fixed roof cone tank, identified as Tank No. 31, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(E) One (1) fixed roof cone tank, identified as Tank No. 32, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(F) One (1) tank, identified as Skid Tank, constructed in 1960, with a capacity of 576 gallons. [40 CFR 63, Subpart CC]
(G) One (1) tank, identified as Dock Tank, constructed in 1950, with a capacity of 564 gallons. [40 CFR 63, Subpart CC]

(H) One (1) upstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]

(I) One (1) downstream barge containment, constructed in 1942, with a capacity of 12,209 gallons. [40 CFR 63, Subpart CC]

(J) Pipeline Valves: Gas Stream. [40 CFR 63, Subpart CC]

(K) Pipeline Valves: Light Liquid. [40 CFR 63, Subpart CC]

(L) Pipeline Valves: Heavy Liquid. [40 CFR 63, Subpart CC]

(M) Open Ended Valves. [40 CFR 63, Subpart CC]

(N) Flanges. [40 CFR 63, Subpart CC]

(O) Pump Seals: Light Liquid. [40 CFR 63, Subpart CC]

(P) Pump Seals: Heavy Liquid. [40 CFR 63, Subpart CC]

(Q) Drains. [40 CFR 63, Subpart CC]

(R) Vessel relief valves. [40 CFR 63, Subpart CC]

The source also consists of the following insignificant activities:

(a) Three (3) silos with polyester bag filters, installed in the late 1950’s, containing lime, soda ash, and ferric sulfate used to process water for the plant.

(b) One (1) river water treatment operation, installed in the late 1950’s. This operation removes material from the river water so the water may be used in refinery processes.

(c) One (1) dry storage and handling operation, installed in the late 1950’s, handling limestone, sand, river silt, and similar materials associated with the river water treatment operation.

Emission Units and Pollution Control Equipment

As part of this permitting action, the source requested to add the following existing emission unit(s) constructed under the provisions of 326 IAC 2-1.1-3 (Exemptions):

(a) One (1) aboveground storage tank, Tank 280W, holding hydrostatic test water.

(b) Unpaved roads

The total potential to emit of the emission unit(s) is less than levels specified at 326 IAC 2-1.1-3(e)(1)(A) through (G) and the addition of the emission unit(s) did not require the source to transition to a higher operation permit level. Therefore, pursuant to 326 IAC 2-1.1-3(e), the modification approval requirements under 326 IAC 2-7-10.5 , including the requirement to submit an application, do not apply to the emission unit(s). The addition of these new exempt emission units to an existing major PSD stationary source is not major because the Emissions Increase of each PSD regulated pollutant is less than the PSD significant level (i.e., the modification does not cause a Significant Emissions Increase). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply (see Appendix A of this Technical Support Document for detailed emission calculations).
**Enforcement Issue**

There are no enforcement actions pending.

**Emission Calculations**

See Appendix A of this Technical Support Document for detailed emission calculations.

**County Attainment Status**

The source is located in Posey County.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Designation</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>Better than national standards.</td>
</tr>
<tr>
<td>CO</td>
<td>Unclassifiable or attainment effective November 15, 1990.</td>
</tr>
<tr>
<td>O₃</td>
<td>Unclassifiable or attainment effective January 16, 2018, for the 2015 8-hour ozone standard.</td>
</tr>
<tr>
<td>PM₂₅</td>
<td>Unclassifiable or attainment effective April 15, 2015, for the 2012 annual PM₂₅ standard.</td>
</tr>
<tr>
<td>PM₁₀</td>
<td>Unclassifiable effective November 15, 1990.</td>
</tr>
<tr>
<td>NO₂</td>
<td>Unclassifiable or attainment effective January 29, 2012, for the 2010 NO₂ standard.</td>
</tr>
<tr>
<td>Pb</td>
<td>Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.</td>
</tr>
</tbody>
</table>

(a) **Ozone Standards**

Volatile organic compounds (VOC) and Nitrogen Oxides (NOₓ) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOₓ emissions are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOₓ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) **PM₂₅**

Posey County has been classified as attainment for PM₂₅. Therefore, direct PM₂₅, SO₂, and NOₓ emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) **Other Criteria Pollutants**

Posey County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

**Fugitive Emissions**

Since this source is classified as a petroleum refinery, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).
Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of Utility Air Regulatory Group v. EPA, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA’s guidance states that U.S. EPA will no longer require PSD or Title V permits for sources “previously classified as ‘Major’ based solely on greenhouse gas emissions.”

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

<table>
<thead>
<tr>
<th>Unrestricted Potential Emissions (ton/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM¹</td>
</tr>
<tr>
<td>-----</td>
</tr>
<tr>
<td>Total PTE of Entire Source Including Fugitives*</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
</tr>
<tr>
<td>Emission Offset Major Source Thresholds</td>
</tr>
</tbody>
</table>

¹Under the Part 70 Permit program (40 CFR 70), PM₁₀ and PM₂.₅, not particulate matter (PM), are each considered as a "regulated air pollutant."
²PM₂.₅ listed is direct PM₂.₅.
³Single highest source-wide HAP.
*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed unrestricted potential emissions of the source.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10, PM2.5, SO2, NOx, VOC, and CO is equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. The source will be issued a Part 70 Operating Permit Renewal.
Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

<table>
<thead>
<tr>
<th>Potential To Emit of the Entire Source After Issuance of Renewal (tons/year)</th>
<th>PM¹</th>
<th>PM¹₀¹</th>
<th>PM₂.₅¹,₂</th>
<th>SO₂</th>
<th>NOₓ</th>
<th>VOC</th>
<th>CO</th>
<th>Single HAP³</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total PTE of Entire Source Including Fugitives*</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;10</td>
<td>&gt;25</td>
</tr>
<tr>
<td>Title V Major Source Thresholds</td>
<td>NA</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>10</td>
<td>25</td>
</tr>
<tr>
<td>PSD Major Source Thresholds</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Emission Offset Major Source Thresholds</td>
<td>---</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

¹Under the Part 70 Permit program (40 CFR 70), PM₁₀ and PM₂.₅, not particulate matter (PM), are each considered as a "regulated air pollutant."

²PM₂.₅ listed is direct PM₂.₅.

³Single highest source-wide HAP.

*Fugitive HAP emissions are always included in the source-wide emissions.

Appendix A of this TSD reflects the detailed potential to emit of the entire source after issuance.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant, PM, PM₁₀, PM₂.₅, SO₂, NOₓ, VOC, and CO, is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability

Federal rule applicability for this source has been reviewed as follows:

New Source Performance Standards (NSPS) (40 CFR 60):

(a) The requirements of the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db, are applicable to this Permittee because they
are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart Db located at CountryMark Cooperative, LLP.

(b) The requirements of the New Source Performance Standard for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart Dc located at CountryMark Cooperative, LLP.

(c) The requirements of the New Source Performance Standard for Petroleum Refineries, 40 CFR 60, Subpart J, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart J located at CountryMark Cooperative, LLP.

(d) The requirements of the New Source Performance Standard for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60, Subpart Ja, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart Ja located at CountryMark Cooperative, LLP.

(e) The requirements of the New Source Performance Standard for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, 40 CFR 60, Subpart K, are not included in the permit for the storage tanks identified as Nos. 23, 27, 28, 31, 32, Skid Tank, Dock Tank, Upstream Barge Containment and Downstream Barge Containment because they were constructed prior to June 11, 1973.

(f) The requirements of the New Source Performance Standards for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, 40 CFR 60, Subpart Kb and 326 IAC 12, are not included in the permit for the five (5) reconstructed tanks because their volume is less than 75 cubic meters (19,813 gallons) each.

(g) The requirements of the New Source Performance Standard 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, 40 CFR 60, Subpart VV, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart VV located at CountryMark Cooperative, LLP.

(h) This source is not subject to the New Source Performance Standards for Bulk Gasoline Terminals (40 CFR 60, Subpart XX), because it is not a bulk gasoline terminal as defined in 40 CFR 60.501. However, pursuant to 40 CFR Part 63.422(a) (Subpart R), the one (1) barge loading and unloading facility must comply with the provisions of 40 CFR 60, subpart XX as follows:

(1) 40 CFR Part 60.502

(i) The requirements of the New Source Performance Standard for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart VVa, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, the reconstructed tanks are not subject to the requirements 40 CFR 60, Subpart VV because they are used for storage of petroleum products, not the manufacturing of synthetic organic chemicals.

(j) The requirements of the New Source Performance Standard for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006, 40 CFR 60, Subpart GGG, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC.
However, there are no units subject to the requirements 40 CFR 60, Subpart GGG located at CountryMark Cooperative, LLP.

(k) The requirements of the New Source Performance Standard for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after November 7, 2006, 40 CFR 60, Subpart GGGa, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart GGGa located at CountryMark Cooperative, LLP.

(l) The requirements of the New Source Performance Standard for VOC Emissions for Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQ, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart QQ located at CountryMark Cooperative, LLP.

(m) The requirements of the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII, are applicable to this Permittee because they are one source with CountryMark Refining and Logistics, LLC. However, there are no units subject to the requirements 40 CFR 60, Subpart IIII located at CountryMark Cooperative, LLP.

(n) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit.

National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR 61):

(a) The requirements of the National Emission Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources) of Benzene, 40 CFR 61, Subpart J, are still not included in the permit because this subpart applies to sources that are intended to operate in benzene service. In benzene service is defined as a piece of equipment either contains or contacts a fluid (Liquid or gas) that is at least 10 percent benzene by weight as determined according to the provisions of §61.245(d). The fuel that is handled by this facility contains less than 10 percent benzene. Therefore these requirements are not included in the permit.

(b) The requirements of the National Emission Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources), 40 CFR 61, Subpart V, are still not included in the permit because this subpart applies to sources that are in VHAP service. In VHAP service is defined as a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP). The fuel that is handled by this facility contains less than 10 percent of a single VHAP. Therefore these requirements are not included in the permit.

(c) The requirements of the National Emission Standards for Hazardous Air Pollutants for Benzene Emissions From Benzene Storage Vessels (40 CFR 61, Subpart Y) are still not included in the permit because there are no storage vessel that store benzene having a specific gravity within the range of specific gravities specified in ASTM D836-84 for Industrial Grade Benzene, ASTM D835-85 for Refined Benzene-485, ASTM D2359-85a or 93 for Refined Benzene-535, and ASTM D4734-87 or 96 for Refined Benzene-545 at the source.

(d) The requirements of the National Emission Standards for Hazardous Air Pollutants for Benzene Emissions from Benzene Transfer Operations (40 CFR 61, Subpart BB) are still not included in the permit for the barge loading and unloading facility because pursuant to 40 CGR 61.300(a), loading of gasoline, crude oil, and petroleum distillates (e.g., fuel oil, diesel, or kerosene) are specifically exempted from this rule.

National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR 63):

(a) This source is not subject to National Emission Standards for Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry (40 CFR 63, Subpart F) because it does not
manufacture as a primary product and of the chemicals listed in 40 CFR 63.100(b)(1) or use as a reactant or manufacture as a product or co-product any of the chemicals listed in Table 2 of 40 CFR 63, Subpart F.

(b) This source is not subject to National Emission Standards for Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater (40 CFR 63, Subpart G) because this source is not subject to 40 CFR 63, Subpart F, as described above.

(c) The requirements of the National Emission Standards for Hazardous Air Pollutants for Equipment Leaks (40 CFR 63, Subpart H) are not included in this permit because the source is not subject to a specific subpart in 40 CFR 63 that references Subpart H.

(d) The requirements of the National Emission Standards for Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks (40 CFR 63, Subpart I) are not included in this permit because this source does not operate one of the processes listed in 40 CFR 63.190(b)(1)-(6).

(e) This source (Plant 1 and Plant 2) will emit greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. The Refinery portion of the source is subject to 40 CFR Part 63, Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries). Pursuant to 40 CFR 63.650, Subpart CC, 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 shall comply with Subpart R. Therefore, the river dock terminal is subject 40 CFR Part 63, Subpart R (National Emissions Standards for Gasoline Distribution Facilities), which are incorporated by reference as 326 IAC 20-10-1. The one (1) barge loading and unloading facility located at the river dock terminal is subject to the following portions of 40 CFR Part 63, Subpart R (National Emissions Standards for Gasoline Distribution Facilities). The unit subject to this rule include the following:

(1) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas.

This source is subject to the following portions of Subpart R.

(1) 40 CFR Part 63.420 (i)
(2) 40 CFR Part 63.421
(3) 40 CFR Part 63.422 (a-c)
(4) 40 CFR Part 63.425 (a-c), (e-h)
(5) 40 CFR Part 63.427 (a-b)
(6) 40 CFR Part 63.428 (b), (c), (g)(1), (h)(1-3)

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63, Subpart R.

(f) This source is not subject to 40 CFR Part 63, Subpart Y (National Emission Standards for Marine Tank Vessel Loading Operations), because it does not have an annual throughput greater than or equal to ten (10) million barrels of gasoline or two hundred (200) million barrels of crude oil and does meet the definition of a source with emissions less than 10 and 25 tons under 40 CFR 63.561.

(g) This source (Plant 1 and Plant 2) will emit greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. The Refinery portion of the source is subject to 40 CFR Part 63, Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries). Pursuant to 40 CFR 63.420 (i), Subpart R, a bulk gasoline
terminal or pipeline breakout station with a SIC code 2911, located within a contiguous area and under common control with a refinery is subject to Subpart CC, 63.650. The units subject to this rule include the following:

(1) One (1) barge loading and unloading facility, constructed in 1952 and approved in 2019 for modification, with emissions controlled by an enclosed vapor combustion unit (VCU) with a maximum natural gas usage of 0.53 MMCF/yr, for pilot gas, and a maximum propane usage of 57.82 MMCF/yr, for enrichment gas.

Insignificant Activities

(2) 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.

(A) One (1) fixed roof cone tank, identified as Tank No. 23, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(B) One (1) fixed roof cone tank, identified as Tank No. 27, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(C) One (1) fixed roof cone tank, identified as Tank No. 28, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(D) One (1) fixed roof cone tank, identified as Tank No. 31, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(E) One (1) fixed roof cone tank, identified as Tank No. 32, constructed in 2016, with a capacity of 16,000 gallons, storing RVP or 6 or less material. [40 CFR 63, Subpart CC]

(F) One (1) tank, identified as Skid Tank, constructed in 1960, with a capacity of 576 gallons.

(G) One (1) tank, identified as Dock Tank, constructed in 1950, with a capacity of 564 gallons.

(H) One (1) upstream barge containment, constructed in 1942, with a capacity of 12,209 gallons.

(I) One (1) downstream barge containment, constructed in 1942, with a capacity of 12,209 gallons.

(J) Pipeline Valves: Gas Stream.

(K) Pipeline Valves: Light Liquid.

(L) Pipeline Valves: Heavy Liquid.

(M) Open Ended Valves.

(N) Flanges.

(O) Pump Seals: Light Liquid.
(P) Pump Seals: Heavy Liquid.

(Q) Drains.

(R) Vessel relief valves.

This source is subject to the following portions of Subpart CC.

(1) 40 CFR 63.640
(2) 40 CFR 63.641
(3) 40 CFR 63.642
(4) 40 CFR 63.643
(5) 40 CFR 63.644
(6) 40 CFR 63.645
(7) 40 CFR 63.646
(8) 40 CFR 63.647
(9) 40 CFR 63.648
(10) 40 CFR 63.649
(11) 40 CFR 63.650
(12) 40 CFR 63.651
(13) 40 CFR 63.652
(14) 40 CFR 63.653
(15) 40 CFR 63.654

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR 63, Subpart CC.

(h) The requirements of the National Emission Standards Hazardous Air Pollutants for Equipment Leaks - Control Level 1 (40 CFR 63, Subpart TT) are not included in this permit because there are no subparts of 40 CFR Part 63 that reference the use of Subpart TT.

(i) The requirements of the National Emission Standards for Hazardous Air Pollutants for Equipment Leaks - Control Level 2 Standards (40 CFR 63, Subpart UU) are not included in this permit because there are no subparts of 40 CFR Part 63 that reference the use of Subpart UU.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants for Storage Vessels (Tanks) - Control Level 2 (40 CFR 63, Subpart WW) are not included in this permit because there are no subparts of 40 CFR Part 63 that reference the use of Subpart WW.

(k) The requirements of the National Emission Standards for Hazardous Air Pollutants for Oil-Water Separators and Organic-Water Separators (40 CFR 63, Subpart VV) are not included in this permit because the facility does not load crude oil or non-crude oil liquids > 5% HAP into tank trucks, rail cars or containers. Pursuant to 40 CFR 63.2338(c), in the event any miscellaneous non-exempted material is loaded at the refinery loading rack, this material is also exempt as it is covered by 40 CFR 63 Subpart R, and fugitive components and tanks are covered by 40 CFR 63 Subpart CC.

(l) This source is not subject to the National Emission Standards for Hazardous Air Pollutants Area Sources: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR 63, Subpart BBBBB) because the source is a major source of HAPs.

(m) This source is not subject to the National Emission Standards for Hazardous Air Pollutants Area Sources: Gasoline Dispensing Facilities (40 CFR 63, Subpart CCCCCC) because the source is a major source of HAPs.
(n) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included in the permit.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

1. has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;
2. is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and
3. uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

<table>
<thead>
<tr>
<th>Emission Unit/Pollutant</th>
<th>Control Device</th>
<th>Applicable Emission Limitation</th>
<th>Uncontrolled PTE (tons/year)</th>
<th>Controlled PTE (tons/year)</th>
<th>CAM Applicable (Y/N)</th>
<th>Large Unit (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge Loading and Unloading Facility / VOC</td>
<td>VCU</td>
<td>326 IAC 2-2</td>
<td>&gt;100</td>
<td>&lt;100</td>
<td>Y</td>
<td>N</td>
</tr>
</tbody>
</table>

Under the Part 70 Permit program (40 CFR 70), PM is not a regulated air pollutant.

Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for regulated air pollutants (PM10, PM2.5, SO2, NOx, VOC and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy.

Controls: BH = Baghouse, C = Cyclone, DC = Dust Collection System, RTO = Regenerative or Recuperative Thermal Oxidizer, WS = Wet Scrubber, ESP = Electrostatic Precipitator

Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.

The enclosed vapor combustor unit (VCU) has yet to be installed on the existing barge loading and unloading facility. Therefore, the requirements of 40 CFR Part 64, CAM, are currently not applicable to the barge loading and unloading facility as part of this Part 70 permit renewal.

Upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003) and installation of the enclosed vapor combustor unit (VCU), the requirements of 40 CFR Part 64, CAM, are applicable to the barge loading and unloading facility, for VOC upon issuance of the next Part 70 Permit Renewal. A CAM plan must be submitted as part of the next Part 70 Operating Permit Renewal application, upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003) and installation of the enclosed vapor combustor unit (VCU).

State Rule Applicability - Entire Source

State rule applicability for this source has been reviewed as follows:

326 IAC 1-6-3 (Preventive Maintenance Plan)
The source is subject to 326 IAC 1-6-3.
326 IAC 1-5-2 (Emergency Reduction Plans)
The source is subject to 326 IAC 1-5-2.

326 IAC 1-7 (Stack Height Provisions)
This source has the potential to emit of greater than or equal to 25 tons per year of PM or SO2. Therefore, the requirements of 326 IAC 1-7 apply.

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
PSD and Emission Offset applicability is discussed under the Potential to Emit After Issuance section of this document.

2019 Modification
In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2019 Modification permitted under MSM 129-41173-00037, the Permittee shall comply with the following:

(a) Prior to completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003):

(1) The throughput of gasoline to the barge loading and unloading facility (Plt ID: 129-00037) shall be less than 83,891,000 equivalent gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) For the purposes of determining compliance, every gallon of crude oil to the barge loading and unloading facility shall be equivalent to 0.256 gallons of gasoline based on VOC emissions, such that the total gallons of gasoline and gasoline equivalent input does not exceed the limit specified.

(3) Gasoline emissions from the barge loading and unloading facility shall not exceed 0.0039 pounds per gallon of gasoline loaded.

(b) Upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003):

(1) Condition D.1.1(a) is not applicable.

(2) The enclosed vapor combustor unit (VCU) shall control VOC emissions from the barge loading and unloading facility (Plt ID: 129-00037) at all times when the barge loading of gasoline and crude oil is in operation and shall achieve a minimum overall VOC control efficiency (capture and destruction efficiency) of 85.0%.

(3) VOC emissions from the barge loading and unloading facility shall not exceed 6.58 lb/hr.

Compliance with these emission limits shall limit the potential to emit of VOCs to less than forty (40) tons per twelve (12) consecutive month period, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2019 Modification permitted under MSM 129-40796-00003 and 129-41173-00037.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).
The operation of the source will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

**326 IAC 2-4.1-1 (New Source Toxics Control)**
This source emits greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. However, the source is not subject to 326 IAC 2-4.1-1 (New Source Toxics Control) because the emission units at Plant 2 were constructed prior to July 27, 1997. Therefore, 326 IAC 2-4.1-1 does not apply.

**326 IAC 2-6 (Emission Reporting)**
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3, an emission statement must be submitted triennially. The first report is due no later than July 1, 2015, and subsequent reports are due every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

**326 IAC 2-7-6(5) (Annual Compliance Certification)**
The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

**326 IAC 5-1 (Opacity Limitations)**
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1).

**326 IAC 6-4 (Fugitive Dust Emissions Limitations)**
Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

**326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)**
This source is not subject to the requirements of 326 IAC 6-5, because the source has potential fugitive particulate emissions of less than twenty-five (25) tons per year.

**326 IAC 6.5 (Particulate Matter Limitations Except Lake County)**
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Posey County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

**326 IAC 6.8 (Particulate Matter Limitations for Lake County)**
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Posey County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

**326 IAC 6.8 (Lake County: Fugitive Particulate Matter)**
Pursuant to 326 IAC 6.8-10-1, this source (located in Posey County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.
State rule applicability has been reviewed as follows:

**326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)**
The enclosed vapor combustion unit (VCU) is not subject to the requirements of 326 IAC 6-2-1, because it is a source of direct heating.

**326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)**
(a) Pursuant to 326 IAC 6-3-1(b)(14), manufacturing processes with potential emissions less than 0.551 pound per hour are exempt from the requirements of 326 IAC 6-3-2. Therefore, the enclosed vapor combustion unit (VCU) is not subject to the requirements of 326 IAC 6-3-2.

(b) Pursuant to 6-3-1, the storage silos, waste water treatment handling operations, and bulk dry storage and handling operations are not subject to the requirements of 326 IAC 6-3-2, because they are not considered part of a manufacturing process as defined in 326 IAC 6-3-1.5(2).

**326 IAC 7-1.1 Sulfur Dioxide Emission Limitations**
No emission units at this plant are subject to 326 IAC 326 IAC 7-1.1 because they have potential to emit (or limited potential to emit) sulfur dioxide (SO2) of less than 25 tons per year or 10 pounds per hour.

**326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)**
This source is not subject to the requirements of 326 IAC 8-1-6 because all units were constructed prior to January 1, 1980.

**326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**
The storage tanks at the source are not subject to the requirements of 326 IAC 8-4-3, because they were all constructed prior to January 1, 1980 and the source is not located in an affected county.

**326 IAC 8-4-4 (Bulk Gasoline Terminals)**
The barge loading and unloading facility is not subject to the requirements of 326 IAC 8-4-4 (Bulk Gasoline Terminals), because it was constructed before January 1, 1980.

**326 IAC 8-4-5 (Bulk Gasoline Plants)**
This source is not subject to the requirements of 326 IAC 8-4-5 (Bulk Gasoline Plants), because it was constructed before January 1, 1980.

**326 IAC 8-4-6 (Gasoline Dispensing Facilities)**
The source is not subject to the requirements of 326 IAC 8-4-6 (Gasoline Dispensing Facilities), because the source does not dispense gasoline into motor vehicle fuel tanks or portable containers, is not a gasoline dispensing facility.

**326 IAC 8-4-7 (Gasoline Transports)**
Plant 1 is not subject to the requirements of 326 IAC 8-4-7 (Gasoline Transports), because it is not a gasoline transport.

**326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties)**
This source is not subject to the requirements of 326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties), because it is not located in Lake, Porter, Clark or Floyd County.

**326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)**
The source is not subject to the requirements of 326 IAC 8-9 (Volatile Organic Liquid Storage Vessels) because this source is not located in Lake, Porter, Clark or Floyd County.

**326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)**
The requirements of 326 IAC 10-3 do not apply to the source, since the source is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).
326 IAC 10-4 (Nitrogen Oxide Budget Trading Program)
This source is not subject to 326 IAC 10-4 because it does not contain an electricity generating unit or a large affected unit as defined in 326 IAC 10-4-2.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source’s failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this source are as follows:

   1. In order to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and upon completion of the Crude Revamp Project, the enclosed vapor combustor unit (VCU) shall be in operation at all times when the barge loading of gasoline and crude oil is in operation.

Testing Requirements:

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Control Device</th>
<th>Timeframe for Testing or Date of Initial Valid Demonstration</th>
<th>Pollutant/Parameter</th>
<th>Frequency of Testing</th>
<th>Authority</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge Loading and Unloading Facility</td>
<td>Vapor Combustor Unit (VCU)</td>
<td>No later than 180 days after startup of the VCU or completion of Crude Revamp Project</td>
<td>VOC and Overall VOC Control Efficiency</td>
<td>every 5 years</td>
<td>326 IAC 2-2</td>
</tr>
</tbody>
</table>

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

<table>
<thead>
<tr>
<th>Control Device</th>
<th>Type of Parametric Monitoring</th>
<th>Frequency</th>
<th>Range or Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vapor Combustion Unit (VCU)</td>
<td>Pilot flame monitoring</td>
<td>Continuous</td>
<td>Presence of pilot flame</td>
</tr>
</tbody>
</table>

These monitoring conditions are necessary because the vapor combustor unit (VCU) for the barge loading and unloading facility must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)).

Compliance determination and monitoring requirements for this source are detailed under the requirements of 40 CFR 63, subpart R and 40 CFR 63, subpart CC.
Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes were made to conditions contained previously issued permits/approvals (these changes may include Title I changes):

1. The source has added insignificant activities to the source. These units have been included in the list of emission units in Section A.5.

2. Effective August 26, 2018, the requirements of 326 IAC 10-4 (Nitrogen Oxides Budget Trading Program) were repealed. Section B - Operational Flexibility of the permit has been revised.

3. Effective June 8, 2019, the requirements of 326 IAC 14-10 (Emission Standards for Asbestos Demolition and Renovation Operations) were amended. Based on the amended rule, Section C.7 - Asbestos Abatement Projects of the permit has been revised.

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on July 19, 2019.

The operation of this stationary petroleum refinery marine vessel loading and unloading dock shall be subject to the conditions of the attached proposed Part 70 Administrative Operating Permit Renewal No. 129-41688-00037.

The staff recommends to the Commissioner that the Part 70 Administrative Operating Permit Renewal be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Michaela Hecox, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 233-3130 or (800) 451-6027, and ask for Michaela Hecox or (317) 233-3130.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.
## Exempt Unit Summary

**Company Name:** CountryMark Refining and Logistics, LLC  
**Source Address:** South Mann and West Ohio St., Mount Vernon, IN 47620  
**TV Renewal Administrative Permit No.:** 129-41688-00037  
**Reviewer:** Michaela Hecox

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5</th>
<th>SO₂</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
<th>Single HAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>RD Tank 280W</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1.67E-06</td>
<td>-</td>
</tr>
<tr>
<td>Valve and Pump Fugitives</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.02</td>
<td>6.57E-04</td>
<td>1.86E-04</td>
</tr>
<tr>
<td>Unpaved Roads</td>
<td>0.03</td>
<td>0.01</td>
<td>8.31E-04</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<td><strong>Total</strong></td>
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<td>0.02</td>
<td>0.00</td>
<td>6.57E-04</td>
<td>1.86E-04</td>
</tr>
</tbody>
</table>
## Appendix A: Emission Calculations

### PTE Summary (Phase I)

**Company Name:** CountryMark Refining and Logistics, LLC  
**Source Address:** South Mann and West Ohio St., Mount Vernon, IN 47620  
**TV Renewal Administrative Permit No.:** 129-41688-00037  
**Reviewer:** Michaela Hecox

### Uncontrolled Potential to Emit (tons/yr)

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO$_2$</th>
<th>NO$_x$</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks, Loading, Unloading, and Fugitive Emissions</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>Dry Storage Silos and Handling Operations</td>
<td>110.81</td>
<td>110.81</td>
<td>110.81</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>Total</td>
<td>110.81</td>
<td>110.81</td>
<td>110.81</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>CountryMark Refining and Logistics, LLC (129-00003)</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;15</td>
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<tr>
<td>Source Wide Total</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;25</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5

### Potential to Emit after Control (tons/yr)

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO$_2$</th>
<th>NO$_x$</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks, Loading, Unloading, and Fugitive Emissions</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>Dry Storage Silos and Handling Operations</td>
<td>1.11</td>
<td>1.11</td>
<td>1.11</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>Total</td>
<td>1.11</td>
<td>1.11</td>
<td>1.11</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>219.73</td>
</tr>
<tr>
<td>CountryMark Refining and Logistics, LLC (129-00003)</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;15</td>
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<td>Source Wide Total</td>
<td>&gt;100</td>
<td>&gt;100</td>
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<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;25</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5

### Potential to Emit after Issuance (tons/yr)

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO$_2$</th>
<th>NO$_x$</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks, Loading, Unloading, and Fugitive Emissions</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>166.59</td>
</tr>
<tr>
<td>Dry Storage Silos and Handling Operations</td>
<td>110.81</td>
<td>110.81</td>
<td>110.81</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<td>Total</td>
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<td>110.81</td>
<td>110.81</td>
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<td>-</td>
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<tr>
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<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
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<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;25</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5
Appendix A: Emission Calculations
PTE Summary (Phase I and Phase II)

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620
TV Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks, Loading, Unloading, and Fugitive Emissions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dry Storage Silos and Handling Operations</td>
<td>110.81</td>
<td>110.81</td>
<td>110.81</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>219.73</td>
</tr>
<tr>
<td>Vapor Combustor Unit (VCU)**</td>
<td>0.06</td>
<td>0.22</td>
<td>0.22</td>
<td>0.02</td>
<td>4.38</td>
<td>0.16</td>
<td>2.45</td>
<td>1.99E-05</td>
</tr>
<tr>
<td>**Total</td>
<td>110.87</td>
<td>111.04</td>
<td>111.04</td>
<td>0.02</td>
<td>4.38</td>
<td>0.16</td>
<td>2.45</td>
<td>1.99E-05</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5

** Emissions are from fuel combustion of the VCU if the VCU is installed upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003).

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>CountryMark Refining and Logistics, LLC (129-00003)</td>
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<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
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<td>&gt;100</td>
<td>&gt;25</td>
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<tr>
<td>Source Wide Total</td>
<td>&gt;100</td>
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<td>&gt;100</td>
<td>&gt;25</td>
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** Emissions are from fuel combustion of the VCU if the VCU is installed upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003).

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanks, Loading, Unloading, and Fugitive Emissions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dry Storage Silos and Handling Operations</td>
<td>1.11</td>
<td>1.11</td>
<td>1.11</td>
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<td></td>
<td></td>
<td>34.43</td>
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<tr>
<td>Vapor Combustor Unit (VCU)**</td>
<td>0.06</td>
<td>0.22</td>
<td>0.22</td>
<td>0.02</td>
<td>4.38</td>
<td>0.16</td>
<td>2.45</td>
<td>1.99E-05</td>
</tr>
<tr>
<td>**Total</td>
<td>1.16</td>
<td>1.33</td>
<td>1.33</td>
<td>0.02</td>
<td>4.38</td>
<td>0.16</td>
<td>2.45</td>
<td>1.99E-05</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5

** Emissions are from fuel combustion of the VCU if the VCU is installed upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003).

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>PM</th>
<th>PM10</th>
<th>PM2.5*</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>Total HAPs</th>
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</thead>
<tbody>
<tr>
<td>CountryMark Refining and Logistics, LLC (129-00003)</td>
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<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;25</td>
</tr>
<tr>
<td>Source Wide Total</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;25</td>
</tr>
</tbody>
</table>

* PM2.5 listed is direct PM2.5

** Emissions are from fuel combustion of the VCU if the VCU is installed upon completion of the Crude Revamp Project for CountryMark Refining and Logistics, LLC (129-00003).
Appendix A: Emission Calculations

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620

V Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

Appendix A: Emission Calculations
Tanks, Loading, Unloading, and Fugitive Emissions

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620

TV Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

Barge Loading
Refinery to Riverdock Terminal Pipelines

<table>
<thead>
<tr>
<th>Pumping rate</th>
<th>bbl/hr</th>
<th>bbl/day*</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude line</td>
<td>3,800</td>
<td>91,200</td>
<td></td>
</tr>
<tr>
<td>Product line</td>
<td>3,500</td>
<td>84,000</td>
<td></td>
</tr>
<tr>
<td>Residual line</td>
<td>1,400</td>
<td>33,600</td>
<td></td>
</tr>
</tbody>
</table>

*Note: loading 24 hr/day is shown for comparison purposes. Barge loading is operationally restricted to 4,380 hr/yr for barge connection/disconnection, docking and undocking activities.

Actual 2014 barge loading - 279,000 bbl gasoline, 70,700 bbl distillates, 168,900 bbl residual oil, and 279,900 bbl crude oil

Worst case potential emissions calculation - including consideration of the operational bottleneck of barge connection/disconnection operations.

<table>
<thead>
<tr>
<th>Material Loaded</th>
<th>bbl/day</th>
<th>Barrel/Year at 4,380 hr/yr</th>
<th>Gallons/year</th>
<th>Barge Loading Emission Factor, lb/1000 gallons</th>
<th>Potential VOC Emissions, ton/yr</th>
<th>Control Efficiency (Capture and Destruction), %</th>
<th>Controlled VOC Emissions, ton/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>14,900</td>
<td>2,646,250</td>
<td>111,142,500</td>
<td>3.9</td>
<td>216.73</td>
<td>85.50%</td>
<td>0.18</td>
</tr>
<tr>
<td>Distillates/Fuel Oils</td>
<td>21,000</td>
<td>3,832,500</td>
<td>160,965,000</td>
<td>0.012</td>
<td>0.97</td>
<td>97.0%</td>
<td>0.00</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>217.69</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Or, not in addition to Gasoline/Distillates

| Crude Oil | 28,600 | 4,891,000 | 206,422,000 | 1.0 | 102.71 | 0.00 | 0.00 |

After Project Enclosed Vapor Combustor - 95% capture (TCEQ 2012 Guidance), 90% destruction (Manufacturer's Guarantee)

Enclosed Vapor Combustor NOx factor manufacturer's guarantee - 0.0334 lb/1000 gallons loaded (4 Mg/l)
Enclosed Vapor Combustor CO factor manufacturer's guarantee - 0.0835 lb/1000 gallons loaded (10 Mg/l)

<table>
<thead>
<tr>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>napthalene</td>
<td>0.175</td>
<td>0.000</td>
<td>napthalene</td>
<td>0.3215</td>
<td>0.000</td>
<td>napthalene</td>
<td>0.005</td>
<td>0.000</td>
<td>napthalene</td>
<td>0.005</td>
<td>0.000</td>
</tr>
<tr>
<td>toluene</td>
<td>0.69</td>
<td>0.004</td>
<td>toluene</td>
<td>0.6946</td>
<td>0.007</td>
<td>toluene</td>
<td>0.05</td>
<td>0.019</td>
<td>toluene</td>
<td>0.05</td>
<td>0.019</td>
</tr>
<tr>
<td>xylene</td>
<td>0.89</td>
<td>0.003</td>
<td>xylene</td>
<td>0.7725</td>
<td>0.004</td>
<td>xylene</td>
<td>0.18</td>
<td>0.019</td>
<td>xylene</td>
<td>0.18</td>
<td>0.019</td>
</tr>
<tr>
<td>benzene</td>
<td>0.321</td>
<td>0.005</td>
<td>benzene</td>
<td>0.5455</td>
<td>0.002</td>
<td>benzene</td>
<td>0.069</td>
<td>0.001</td>
<td>benzene</td>
<td>0.069</td>
<td>0.001</td>
</tr>
<tr>
<td>cumene</td>
<td>0.084</td>
<td>0.005</td>
<td>cumene</td>
<td>0.3621</td>
<td>0.000</td>
<td>cumene</td>
<td>0.05</td>
<td>0.007</td>
<td>cumene</td>
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<td>0.007</td>
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<td>cyclohexane</td>
<td>1.14</td>
<td>0.017</td>
<td>cyclohexane</td>
<td>1.173</td>
<td>0.003</td>
<td>cyclohexane</td>
<td>0.036</td>
<td>0.003</td>
<td>cyclohexane</td>
<td>0.036</td>
<td>0.003</td>
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<tr>
<td>ethylbenzene</td>
<td>0.362</td>
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<td>ethylbenzene</td>
<td>1.5474</td>
<td>0.001</td>
<td>ethylbenzene</td>
<td>0.04</td>
<td>0.005</td>
<td>ethylbenzene</td>
<td>0.04</td>
<td>0.005</td>
</tr>
<tr>
<td>n-hexane</td>
<td>2.43</td>
<td>0.055</td>
<td>n-hexane</td>
<td>2.103</td>
<td>0.009</td>
<td>n-hexane</td>
<td>0.005</td>
<td>0.011</td>
<td>n-hexane</td>
<td>0.005</td>
<td>0.011</td>
</tr>
<tr>
<td>2,2,4-trimethylpentane</td>
<td>2.06</td>
<td></td>
<td>2.06</td>
<td></td>
<td>0.005</td>
<td>0.000</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Total HAPs: 11.83
Appendix A: Emission Calculations

Tanks, Loading, Unloading, and Fugitive Emissions (Limited PTE)

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620
V Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

Barge Loading

Refinery to Riverdock Terminal Pipelines

Barge Loading

<table>
<thead>
<tr>
<th>Pumping rate</th>
<th>Refinery to Riverdock Pipelines</th>
<th>barrel/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude line</td>
<td>3,800</td>
<td>91,200</td>
</tr>
<tr>
<td>Product line</td>
<td>3,500</td>
<td>84,000</td>
</tr>
<tr>
<td>Residual line</td>
<td>1,400</td>
<td>33,600</td>
</tr>
</tbody>
</table>

Note - loading 24 hr/day is shown for comparison purposes. Barge loading is operationally restricted to 4,380 hr/yr for barge connection/disconnection, docking and undocking activities.

Actual 2014 barge loading - 279,000 bbl gasoline, 70,700 bbl distillates, 168,900 bbl residual oil, and 279,900 bbl crude oil

Worst case potential emissions calculation - including consideration of the operational bottleneck of barge connection/disconnection operations.

<table>
<thead>
<tr>
<th>Material Loaded</th>
<th>gallons/yr</th>
<th>Benzene</th>
<th>Ethylbenzene</th>
<th>Toluene</th>
<th>Xylene</th>
<th>n-Hexane</th>
<th>Naphthalene</th>
<th>Cumene</th>
<th>2,2,4 - Trimethylpentane</th>
<th>Cyclohexane</th>
<th>Biphenyl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>10,945</td>
<td>0.25</td>
<td>0.15</td>
<td>0.71</td>
<td>1.46</td>
<td>0.02</td>
<td>0.03</td>
<td>0.76</td>
<td>0.54</td>
<td></td>
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</tr>
<tr>
<td>Product line</td>
<td>21,000</td>
<td>0.25</td>
<td>0.16</td>
<td>1.20</td>
<td>0.73</td>
<td>1.47</td>
<td>0.02</td>
<td>0.03</td>
<td>0.76</td>
<td>0.54</td>
<td></td>
</tr>
<tr>
<td>Residual line</td>
<td>21,000</td>
<td>0.25</td>
<td>0.16</td>
<td>1.20</td>
<td>0.73</td>
<td>1.47</td>
<td>0.02</td>
<td>0.03</td>
<td>0.76</td>
<td>0.54</td>
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</tr>
<tr>
<td>Total</td>
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<td></td>
<td></td>
<td>0.26</td>
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</tr>
</tbody>
</table>

Or, not in addition to Gasoline/Distillates

Crude Oil* 26,800 4,891,000 205,422,000 1.0 102.71

* Worst case crude barge loading volume, all crude is loaded to barges and not processed into product.

Crude Oil

<table>
<thead>
<tr>
<th>Tank No.</th>
<th>Total HAPS:</th>
<th>10.91</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tank 27</td>
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<td>1.79E-03</td>
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<tr>
<td>Tank 28</td>
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</tr>
<tr>
<td>Tank 31</td>
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<td>0.00</td>
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<tr>
<td>Tank 32</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Total</td>
<td>102.71</td>
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<table>
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<tr>
<th>Total Barge Loading and Tanks</th>
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</thead>
<tbody>
<tr>
<td>Total</td>
<td>1.00</td>
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</table>

<table>
<thead>
<tr>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
<th>Fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>naphthenic</td>
<td>0.175</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>toluene</td>
<td>0.69</td>
<td>0.003</td>
<td>0.003</td>
</tr>
<tr>
<td>xyylene</td>
<td>0.89</td>
<td>0.002</td>
<td>0.002</td>
</tr>
<tr>
<td>benzene</td>
<td>0.321</td>
<td>0.005</td>
<td>0.005</td>
</tr>
<tr>
<td>cumene</td>
<td>0.084</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>cyclohexane</td>
<td>1.14</td>
<td>0.017</td>
<td>0.017</td>
</tr>
<tr>
<td>ethylbenzene</td>
<td>0.362</td>
<td>0.001</td>
<td>0.001</td>
</tr>
<tr>
<td>n-hexane</td>
<td>2.43</td>
<td>0.005</td>
<td>0.005</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Compound</th>
<th>Liquid Concentration</th>
<th>Vapor mass fraction</th>
<th>Fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>naphthenic</td>
<td>0.3215</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>toluene</td>
<td>0.69</td>
<td>0.007</td>
<td>0.007</td>
</tr>
<tr>
<td>xyylene</td>
<td>7.7725</td>
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<td>0.004</td>
</tr>
<tr>
<td>benzene</td>
<td>0.5455</td>
<td>0.002</td>
<td>0.002</td>
</tr>
<tr>
<td>cumene</td>
<td>0.3521</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
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<td>1.173</td>
<td>0.003</td>
<td>0.003</td>
</tr>
<tr>
<td>ethylbenzene</td>
<td>1.5474</td>
<td>0.001</td>
<td>0.001</td>
</tr>
<tr>
<td>n-hexane</td>
<td>2.103</td>
<td>0.009</td>
<td>0.009</td>
</tr>
<tr>
<td>2,2,4-trimethylpentane</td>
<td>2.96</td>
<td>0.005</td>
<td>0.005</td>
</tr>
</tbody>
</table>

Total HAPS: 10.91
### Appendix A: Emission Calculations

**Barge Loading Emissions - Hybrid Evaluation**

**Company Name:** CountryMark Refining and Logistics, LLC  
**Source Address:** South Mann and West Ohio St., Mount Vernon, IN 47620  
**TV Renewal Administrative Permit No.:** 129-41688-00037  
**Reviewer:** Michaela Hecox

Existing Barge Loading Facility - Title V Permit No. T129-35011-00037

<table>
<thead>
<tr>
<th></th>
<th>Average uncontrolled loading loss VOC emission factor (lb/1000 gal)</th>
<th>Before Project Overall control efficiency (Capture and Destruction), %</th>
<th>Before Project Throughput (gallons/year)</th>
<th>Before Project VOC (ton/yr)</th>
<th>After Project Throughput (gallons/year)</th>
<th>After Project Overall control efficiency (Capture and Destruction), %</th>
<th>After Project VOC (ton/yr)</th>
<th>After Project NOx (ton/yr)</th>
<th>After Project CO (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge Loading - Gasoline</td>
<td>3.9</td>
<td>0.00</td>
<td>67,078,469</td>
<td>130.80</td>
<td>101,540,309</td>
<td>85.50</td>
<td>28.71</td>
<td>1.70</td>
<td>4.24</td>
</tr>
<tr>
<td>Barge Loading - Crude Oil</td>
<td>1.0</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>987,070</td>
<td>85.50</td>
<td>0.07</td>
<td>0.016</td>
<td>0.041</td>
</tr>
<tr>
<td>Barge Loading - Distillates</td>
<td>0.012</td>
<td>0.00</td>
<td>11,220,737</td>
<td>0.07</td>
<td>8,838,273</td>
<td>0.00</td>
<td>0.05</td>
<td>0.001</td>
<td>N/A</td>
</tr>
<tr>
<td>Barge Loading - Heavy Oil</td>
<td>0.00005</td>
<td>0.00</td>
<td>5,355,040</td>
<td>0.0002</td>
<td>11,608,054</td>
<td>0.00</td>
<td>0.0005</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>130.87</td>
<td></td>
<td>28.84</td>
<td></td>
<td>1.71</td>
<td></td>
<td>4.28</td>
</tr>
</tbody>
</table>

**Basis:**  
Uncontrolled loading loss VOC emission factor - AP 42 Table 5.2-2  
Throughput before project based upon 2018 throughput - largest annual throughput in last 5 years, demonstrating the could be accomodated throughput prior to the project.  
After Project Enclosed Vapor Combustor - 95% capture (TCEQ 2012 Guidance), 90% destruction (Manufacturer's Guarantee)  
Enclosed Vapor Combustor NOx factor manufacturer's guarantee - 0.0334 lb/1000 gallons loaded (4 Mg/l)  
Enclosed Vapor Combustor CO factor manufacturer's guarantee - 0.0835 lb/1000 gallons loaded (10 Mg/l)
Barge Loading Enclosed Vapor Combustor - Other fuel usage

Manufacturer assumes natural gas for pilot and propane for enrichment gas.

Emission estimates assume worst case use of propane for both.

Fuel Usage (MMCF/yr)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM</th>
<th>PM10</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline (Actual) Emissions in tons/yr before project</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Projected Actual Emission in tons/yr after project</td>
<td>0.06</td>
<td>0.22</td>
<td>0.22</td>
<td>0.02</td>
<td>4.38</td>
<td>0.16</td>
<td>2.45</td>
</tr>
</tbody>
</table>

Natural Gas emissions are multiplied by 1.5, see AP-42, Table 1.5-1 footnote to adjust natural gas NOx emissions to propane NOx emissions.

Methodology

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

PM, CO, SO2, NOx, VOC Emission Factors are from AP 42, Table 1.4-2

Barge Loading

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM</th>
<th>PM10</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>2.3E-04</td>
<td>1.48E-04</td>
<td>1.16E-03</td>
<td>6.96E-04</td>
<td>2.06E-04</td>
<td>1.43E-03</td>
<td>1.99E-05</td>
</tr>
<tr>
<td>TOTAL</td>
<td>2.3E-04</td>
<td>1.48E-04</td>
<td>1.16E-03</td>
<td>6.96E-04</td>
<td>2.06E-04</td>
<td>1.43E-03</td>
<td>1.99E-05</td>
</tr>
</tbody>
</table>

Total Barge Loading emissions before project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM</th>
<th>PM10</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>130.87</td>
<td>0.00</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total Barge Loading emissions after project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>PM</th>
<th>PM10</th>
<th>direct PM2.5</th>
<th>SO2</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.06</td>
<td>0.22</td>
<td>0.22</td>
<td>0.02</td>
<td>6.09</td>
<td>29.00</td>
<td>6.73</td>
<td></td>
</tr>
</tbody>
</table>
In the event the Crude Revamp Portion of the project is not completed, the vapor combustor will not be installed.
The alternative limitation for barge loading throughput due to the Unifiner portion of the project only, beginning January 2020 - 83,891,000 equivalent gallons per 12-month period.

<table>
<thead>
<tr>
<th>Average uncontrolled loading loss VOC emission factor (lb/1000 gal)</th>
<th>Before Project Overall control efficiency (Capture and Destruction), %</th>
<th>Before Project Throughput (gallons/year)</th>
<th>Before Project VOC (ton/yr)</th>
<th>After Project Overall control efficiency (Capture and Destruction), %</th>
<th>After Project Throughput (gallons/year)</th>
<th>After Project VOC (ton/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barge Loading - Gasoline</td>
<td>3.9</td>
<td>0.00</td>
<td>67,078,469</td>
<td>130.80</td>
<td>83,891,000</td>
<td>0.00</td>
</tr>
<tr>
<td>Barge Loading - Crude Oil</td>
<td>1.0</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Barge Loading - Distillates</td>
<td>0.012</td>
<td>0.00</td>
<td>11,220,737</td>
<td>0.07</td>
<td>11,220,737</td>
<td>0.00</td>
</tr>
<tr>
<td>Barge Loading - Heavy Oil</td>
<td>0.0009</td>
<td>0.00</td>
<td>5,355,040</td>
<td>0.0002</td>
<td>5,355,040</td>
<td>0.00</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Storage and Loading HAP Emissions - After Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benzene</td>
</tr>
<tr>
<td>tpy</td>
</tr>
<tr>
<td>Barge Loading</td>
</tr>
<tr>
<td>TOTAL</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>HAP to VOC Mass Fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
</tr>
<tr>
<td>Benzene</td>
</tr>
<tr>
<td>Ethylbenzene</td>
</tr>
<tr>
<td>Toluene</td>
</tr>
<tr>
<td>Xylene</td>
</tr>
<tr>
<td>1,2,4-Trimethylbenzene</td>
</tr>
<tr>
<td>n-Hexane</td>
</tr>
<tr>
<td>Naphthalene</td>
</tr>
<tr>
<td>Cyclohexane</td>
</tr>
<tr>
<td>Isopropyl benzene (cumene)</td>
</tr>
<tr>
<td>2,2,4-trimethylpentane</td>
</tr>
</tbody>
</table>
## Appendix A: Emission Calculations

### Tank Assumptions

**Company Name:** CountryMark Refining and Logistics, LLC  
**Source Address:** South Mann and West Ohio St., Mount Vernon, IN 47620  
**TV Renewal Administrative Permit No.:** 129-41688-00037  
**Reviewer:** Michaela Hecox

### Riverdock Storage Tanks - Assumptions

<table>
<thead>
<tr>
<th>Tank No.</th>
<th>Capacity, gallons</th>
<th>Purpose</th>
<th>Basis for Potential Emission Calculation</th>
<th>VOC Potential Emissions, ton/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tank 27</td>
<td>16,800</td>
<td>Occasional storage of kerosene, historically twice per year</td>
<td>Operation year round in distillate service</td>
<td>1.17</td>
</tr>
<tr>
<td>Tank 23</td>
<td>16,800</td>
<td>Pipeline Interface Storage</td>
<td>Maximum of 10 turnovers per year in slop oil service</td>
<td>0.04</td>
</tr>
<tr>
<td>Tank 28</td>
<td>16,800</td>
<td>Pipeline Interface Storage</td>
<td>Maximum of 10 turnovers per year in slop oil service</td>
<td>0.17</td>
</tr>
<tr>
<td>Tank 31</td>
<td>16,800</td>
<td>Pipeline Interface Storage</td>
<td>Maximum of 10 turnovers per year in slop oil service</td>
<td>0.03</td>
</tr>
<tr>
<td>Tank 32</td>
<td>16,800</td>
<td>Pipeline Interface Storage</td>
<td>Maximum of 10 turnovers per year in slop oil service</td>
<td>0.04</td>
</tr>
<tr>
<td>Stripping Tank</td>
<td>576</td>
<td>Receives small amounts of gasoline when a barge that previously held gasoline is switched to diesel service.</td>
<td>Insignificant - less than 1000 gallons capacity, less than 12,000 gallons/yr throughput Potential emission estimate assumes 12,000 gallons throughput of RVP 13 gasoline</td>
<td>0.14</td>
</tr>
<tr>
<td>Dock Tank</td>
<td>564</td>
<td>Fuel tank for boat motor</td>
<td>Insignificant - petroleum fuel dispensing, storage capacity less than 10,500 gallons, dispensing less than 1,300 gallons/day Potential emission estimate assumes 1,300 gallons/day, 365 day/yr, RVP 13 Gasoline</td>
<td>0.54</td>
</tr>
<tr>
<td>Upstream Barge Containment</td>
<td>12,209</td>
<td>Compartments on the stationary barge to catch any drips and leaks.</td>
<td>Insignificant - Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including catch tanks, temporary liquid separators, tanks, and fluid handling equipment. Potential emission estimate assumes one turnover per year, slop oil</td>
<td>0.03</td>
</tr>
<tr>
<td>Downstream Barge Containment</td>
<td>12,209</td>
<td>Compartments on the stationary barge to catch any drips and leaks.</td>
<td>Insignificant - Same as above</td>
<td>0.03</td>
</tr>
</tbody>
</table>

**Total:** 2.18
Appendix A: Emission Calculations
Dry Storage Silos and Handling Operations

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620
TV Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

<table>
<thead>
<tr>
<th>Unit</th>
<th>Throughput (tpy)</th>
<th>PM EF (lb/ton)</th>
<th>PM10 EF (lb/ton)</th>
<th>PM2.5 EF (lb/ton)</th>
<th>PM (tpy)</th>
<th>PM10 (tpy)</th>
<th>PM2.5 (tpy)</th>
<th>Controlled Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lime Mfg. Transfer &amp; Conveying</td>
<td>100740</td>
<td>2.2</td>
<td>2.2</td>
<td>2.2</td>
<td>110.81</td>
<td>110.81</td>
<td>110.81</td>
<td>1.11</td>
</tr>
</tbody>
</table>

**Methodology**

PTE (tpy) = Throughput (tpy) x (EF (lb/ton) / 2000 (lb/ton))
Controlled PTE (tpy) = PTE (tpy) x (1 - 99%)
Appendix A: Emission Calculations
RD Tank 280W

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620
TV Renewal Administrative Permit No.: 129-41588-00037
Reviewer: Michaela Hecox

Riverdock - Insignificant Activity

<table>
<thead>
<tr>
<th>ID</th>
<th>Contents</th>
<th>Volume (gal)</th>
<th>Volume (ft³)</th>
<th>Shell Height (ft)</th>
<th>Diameter (ft)</th>
<th>Liquid Height (ft)</th>
<th>Average Liquid Height (ft)</th>
<th>Turnovers/Year (N)</th>
<th>Throughput (gal/yr), Q</th>
<th>Throughput (bbl/yr), Q</th>
<th>Shell Color</th>
<th>Shell Condition</th>
<th>Roof Color</th>
<th>Roof Condition</th>
<th>Heated (Y/N)</th>
<th>Roof Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>280W</td>
<td>Hydrostatic Test W</td>
<td>42810</td>
<td>5614.602</td>
<td>15.9</td>
<td>21.4</td>
<td>14.9</td>
<td>7.5</td>
<td>52</td>
<td>504554</td>
<td>12001</td>
<td>White</td>
<td>Good</td>
<td>White</td>
<td>Good</td>
<td>Y</td>
<td>Cone</td>
</tr>
</tbody>
</table>

**Riverdock - Insignificant Activity**

**ID Contents**

- **Volume (gal)**: 42810
- **Volume (ft³)**: 5614.602
- **Shell Height (ft)**: 15.9
- **Diameter (ft)**: 21.4
- **Liquid Height (ft)**: 14.9
- **Average Liquid Height (ft)**: 7.5
- **Turnovers/Year (N)**: 52
- **Throughput (gal/yr), Q**: 504554
- **Throughput (bbl/yr), Q**: 12001
- **Shell Color**: White
- **Shell Condition**: Good
- **Roof Color**: White
- **Roof Condition**: Good
- **Heated (Y/N)**: Y
- **Roof Type**: Cone

**SEE NOTES 1 AND 2**

### Constants

- **Cone Roof Slope**: 0.0625 ft/ft
- **Tank Roof Height**: H₀ = S₀ × R₀
- **Cone Roof Outage**: H₀ = (1/3) × H₀
- **Tank Shell Radius**: R₀ = 10.7 ft
- **Tank Shell Height**: H₀ = 15.9 ft
- **Tank Max Liquid Vol**: V₀ = (π/4) × D₂ × H₀
- **Liquid Height**: H₀ = 7.5 ft
- **Max Liquid Height**: H₀ = V₀/[π(4/3)D] = 5614.6 ft³
- **Vapor Space Outage**: H₀ = H₀ - H₁ = H₀
- **Vapor Space Outage**: H₀ = 8.62 ft

**NOTE 1**: Working Loss Turnover Saturation Factor (Kₙ), use formula (180+N)/(6xN) if turnovers are > 36/year, Use Kₙ = 1 if turnovers are ≤ 36/year

**NOTE 2**: Ratio N (turnovers) with days/month and days/year, (# Month Days/365) × N, for use of N in equations

**NOTE 3**: When liquid stock has true vapor pressure greater than 0.1 psia, a more accurate estimate of the vapor space expansion factor is obtained by equation 1-37. If liquid stock has true vapor pressure less than 0.1 use equation 1-5 (KE = 0.0018 x 0.72 x (TAX - TAN) + 0.028 x a x x i)
### Appendix A: Emission Calculations

#### Valve and Pump Fugitives

**Company Name:** CountryMark Refining and Logistics, LLC  
**Source Address:** South Mann and West Ohio St., Mount Vernon, IN 47620  
**TV Renewal Administrative Permit No.:** 129-41688-00037  
**Reviewer:** Michaela Hecox

#### Valve Monitoring Data

<table>
<thead>
<tr>
<th>Compound</th>
<th>Concentration</th>
<th>Vapor Mass Fraction</th>
<th>HAP tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>naphthalene</td>
<td>0.3215</td>
<td>0.000</td>
<td>2.55E-06</td>
</tr>
<tr>
<td>toluene</td>
<td>6.9546</td>
<td>0.007</td>
<td>1.49E-04</td>
</tr>
<tr>
<td>xylene</td>
<td>7.7725</td>
<td>0.004</td>
<td>8.94E-05</td>
</tr>
<tr>
<td>benzene</td>
<td>0.5455</td>
<td>0.002</td>
<td>3.09E-05</td>
</tr>
<tr>
<td>cumene</td>
<td>0.3521</td>
<td>0.000</td>
<td>4.12E-06</td>
</tr>
<tr>
<td>cyclohexane</td>
<td>1.173</td>
<td>0.003</td>
<td>6.80E-05</td>
</tr>
<tr>
<td>ethylbenzene</td>
<td>1.5474</td>
<td>0.001</td>
<td>1.89E-05</td>
</tr>
<tr>
<td>n-hexane</td>
<td>2.103</td>
<td>0.009</td>
<td>1.84E-04</td>
</tr>
<tr>
<td>2,2,4-trimeth</td>
<td>2.96</td>
<td>0.005</td>
<td>9.59E-05</td>
</tr>
</tbody>
</table>

**Total HAP tpy:** 6.42E-04

#### Pump Monitoring Data

<table>
<thead>
<tr>
<th>Compound</th>
<th>Concentration</th>
<th>Vapor Mass Fraction</th>
<th>HAP tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>naphthalene</td>
<td>0.005</td>
<td>0.000</td>
<td>1.04E-08</td>
</tr>
<tr>
<td>toluene</td>
<td>0.05</td>
<td>0.019</td>
<td>4.44E-06</td>
</tr>
<tr>
<td>xylene</td>
<td>0.18</td>
<td>0.019</td>
<td>4.47E-06</td>
</tr>
<tr>
<td>biphenyl</td>
<td>0.0659</td>
<td>0.001</td>
<td>1.50E-07</td>
</tr>
<tr>
<td>benzene</td>
<td>0.005</td>
<td>0.007</td>
<td>1.57E-06</td>
</tr>
<tr>
<td>cyclohexane</td>
<td>0.036</td>
<td>0.003</td>
<td>7.86E-07</td>
</tr>
<tr>
<td>ethylbenzene</td>
<td>0.04</td>
<td>0.005</td>
<td>1.19E-06</td>
</tr>
<tr>
<td>n-hexane</td>
<td>0.005</td>
<td>0.011</td>
<td>2.57E-06</td>
</tr>
</tbody>
</table>

**Total HAP tpy:** 1.52E-05
Appendix A: Emission Calculations
Fugitive Dust Emission - Unpaved Roads

Company Name: CountryMark Refining and Logistics, LLC
Source Address: South Mann and West Ohio St., Mount Vernon, IN 47620
TV Renewal Administrative Permit No.: 129-41688-00037
Reviewer: Michaela Hecox

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Maximum number of vehicles</th>
<th>Number of one-way trips per vehicle</th>
<th>Maximum Weight Loaded (tons/trip)</th>
<th>Weight driven per day (ton/day)</th>
<th>Maximum one-way distance (feet/trip)</th>
<th>Maximum one-way distance (miles/trip)</th>
<th>Maximum one-way distance (miles/day)</th>
<th>Maximum one-way distance (miles/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vehicle (entering plant) (one-way trip)</td>
<td>1</td>
<td>0.14</td>
<td>0.1</td>
<td>40.0</td>
<td>5.7</td>
<td>621</td>
<td>0.118</td>
<td>0.02</td>
</tr>
<tr>
<td>Vehicle (leaving plant) (one-way trip)</td>
<td>1</td>
<td>0.14</td>
<td>0.1</td>
<td>15.0</td>
<td>2.1</td>
<td>621</td>
<td>0.118</td>
<td>0.02</td>
</tr>
</tbody>
</table>

Totals 0.3 7.9 0.0 12.3

Average Vehicle Weight Per Trip = 27.5 tons/trip
Average Miles Per Trip = 0.12 miles/trip

Unmitigated Emission Factor, Ef = \( k \times (s/12)^a \times (W/3)^b \) (Equation 1a from AP-42 13.2.2)

PM PM10 PM2.5
where \( k = 4.9 \) 1.5 0.15 \( \text{lb/mi} \) = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
\( s = 6.0 \) 6.0 6.0 \% = mean \% silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
\( a = 0.7 \) 0.9 0.9 \( \text{constant} \) (AP-42 Table 13.2.2-2 for Industrial Roads)
\( W = 27.5 \) 27.5 27.5 \( \text{tons} \) = average vehicle weight (provided by source)
\( b = 0.45 \) 0.45 0.45 \( \text{constant} \) (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Ex = \( E \times \left[ (365 - P)/365 \right] \) (Equation 2 from AP-42 13.2.2)

Mitigated Emission Factor, Ex = \( E \times \left[ (365 - P)/365 \right] \)
where \( P = 138 \) days of rain greater than or equal to 0.01 inches (from 2018 National Weather Service data for Evansville, IN)

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Mitigated PTE of PM (Before Control) (tons/yr)</th>
<th>Mitigated PTE of PM10 (Before Control) (tons/yr)</th>
<th>Mitigated PTE of PM2.5 (Before Control) (tons/yr)</th>
<th>Mitigated PTE of PM (After Control) (tons/yr)</th>
<th>Mitigated PTE of PM10 (After Control) (tons/yr)</th>
<th>Mitigated PTE of PM2.5 (After Control) (tons/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vehicle (entering plant) (one-way trip)</td>
<td>0.02</td>
<td>0.00</td>
<td>0.00</td>
<td>0.02</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Vehicle (leaving plant) (one-way trip)</td>
<td>0.02</td>
<td>0.00</td>
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Methodology

- Total Weight driven per day (ton/day) = \( \text{Maximum Weight Loaded (tons/trip)} \times \text{Maximum trips per day (trip/day)} \)
- Maximum one-way distance (mi/trip) = \( \text{Maximum one-way distance (miles/trip)} / 5280 \) ft/mile
- Maximum one-way miles (miles/day) = \( \text{Maximum trips per year (trip/day)} \times \text{Maximum one-way distance (miles/trip)} \)
- Average Vehicle Weight Per Trip (ton/trip) = \( \text{SUM} \times \text{Total Weight driven per day (ton/day)} / \text{SUM} \times \text{Maximum trips per day (trip/day)} \)
- Average Miles Per Trip (miles/trip) = \( \text{SUM} \times \text{Maximum one-way miles (miles/day)} / \text{SUM} \times \text{Maximum trips per year (trip/day)} \)
- Mitigated PTE (Before Control) (tons/yr) = \( \text{Mitigated Emission Factor (lb/mile)} \times \text{Average Vehicle Weight Per Trip (ton/trip)} \times (1 - \text{Dust Control Efficiency}) \)

Riverdock averages one truck delivery once every 7 days.
March 9, 2020

Re: Public Notice
CountryMark Refining & Logistics, LLC
Permit Level: Title V - Renewal
Permit Number: 129-41688-00037

Dear Mr. Pankey:

Enclosed is a copy of your draft Title V - Renewal, Technical Support Document, emission calculations, and the Public Notice.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: https://www.in.gov/idem/5474.htm

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Alexandrian, 115 W. 5th Street in Mount Vernon, IN 47620. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Michaela Hecox, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 3-3130 or dial (317) 233-3130.

Sincerely,

Vicki Biddle

Vicki Biddle
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter 4/12/19
March 9, 2020

To: Alexandrian Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: Important Information to Display Regarding a Public Notice for an Air Permit

Applicant Name: CountryMark Refining & Logistics, LLC
Permit Number: 129-41688-00037

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. Please make this information readily available until you receive a copy of the final package.

If you have any questions concerning this public review process, please contact Joanne Smiddle-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library updated 4/2019
Notice of Public Comment

March 9, 2020
CountryMark Refining & Logistics, LLC
129-41688-00037

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has posted on IDEM’s Public Notice website at https://www.in.gov/idem/5474.htm.

The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana’s Air Permitting Program.

Please Note: If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.

Enclosure
PN AAA Cover Letter 2/28/2020
AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

March 9, 2020

A 30-day public comment period has been initiated for:

Permit Number: 129-41688-000037
Applicant Name: CountryMark Refining & Logistics, LLC
Location: Mount Vernon, Posey County, Indiana

The public notice, draft permit and technical support documents can be accessed via the IDEM Air Permits Online site at:
http://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.
### Mail Code 61-53

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<td>Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204</td>
<td>CERTIFICATE OF MAILING ONLY</td>
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<td>Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 (Affected Party)</td>
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<td>John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)</td>
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<td>Ms. Pat Sorensen Environmental Resources Management (ERM) 8425 Woodfield Crossing, Suite 560-W Indianapolis IN 46240 (Consultant)</td>
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**Total number of pieces Listed by Sender**: 15

**Total number of Pieces Received at Post Office**: 15

**Postmaster, Per (Name of Receiving employee)**: The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50,000 per occurrence. The maximum indemnity payable on Express mail merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See [Domestic Mail Manual R900, S913, and S921](https://www.usps.com/pubs/manuals/dmm900.htm) for limitations of coverage on insured and COD mail. See [International Mail Manual](https://www.usps.com/pubs/manuals/imm.htm) for limitations of coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.