**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**
*We Protect Hoosiers and Our Environment.*

*Mitchell E. Daniels Jr.*
**Governor**

*Thomas W. Easterly*
**Commissioner**

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
**www.idem.IN.gov**

TO: Interested Parties / Applicant

DATE: July 1, 2010

RE: Countrymark Cooperative, LLP / 126-25424-00003

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

# Notice of Decision: Approval – Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-6-1(b) or IC 13-15-6-1(a) require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204.

For an **initial Title V Operating Permit**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **thirty (30)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(b).

For a **Title V Operating Permit renewal**, a petition for administrative review must be submitted to the Office of Environmental Adjudication within **fifteen (15)** days from the receipt of this notice provided under IC 13-15-5-3, pursuant to IC 13-15-6-1(a).

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:



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(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of an initial Title V operating permit, permit renewal, or modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impractible to raise such issues, or if the grounds for such objection arose after the comment period.

To petition the U.S. EPA to object to the issuance of a Title V operating permit, contact:

U.S. Environmental Protection Agency
401 M Street
Washington, D.C. 20406

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
FNTVOP.dot12/3/07

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# Part 70 Operating Permit Renewal
# OFFICE OF AIR QUALITY

## Countrymark Cooperative, LLP
## 1200 Refinery Road
## 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.

| Operation Permit No.: T129-25424-00003 | |
|---|---|
| Issued by:<br><br>Chrystal A. Wagner, Section Chief<br>Permits Branch<br>Office of Air Quality | Issuance Date: July 1, 2010<br><br>Expiration Date: July 1, 2015 |

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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, A.3 through A.4 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(15)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary petroleum refinery.

| | |
|---|---|
| Source Address: | 1200 Refinery Road, Mount Vernon, Indiana 47620 |
| Mailing Address: | 1200 Refinery Road, Mount Vernon, Indiana 47620 |
| General Source Phone Number: | (812) 838-8133 |
| SIC Code: | 2911 |
| County Location: | Posey |
| Source Location Status: | Attainment for all criteria pollutants |
| Source Status: | Part 70 Operating Permit Program<br>Major Source, under PSD Rules<br>Major Source, Section 112 of the Clean Air Act<br>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 marine vessel loading and unloading river dock terminal consists of two (2) plants:

(a) Plant 1, the refinery, is located at 1200 Refinery Road, Mount Vernon, IN 47620; and

(b) Plant 2, the river dock terminal, is located at South Mann St. and West Ohio St., Mount Vernon, IN 47620.

On November 24, 2003, in Significant Permit Modification (129-17940-00003), a source determination concluded that Plant 1 (the refinery) and Plant 2 (the river dock terminal) are under the common control of Countrymark Cooperative, LLP and will be considered one source. These two plants are considered one source because they are located on adjacent properties, are under common ownership, and belong to the same industrial grouping. Therefore, the term “source” in the Part 70 documents refers to both Plant 1 and Plant 2 as one source.

Separate Part 70 renewal permits are being issued to Countrymark Cooperative, LLP, solely for administrative purposes:

(a) Plant 1, 129-00003: T129-25424-00003

(b) Plant 2, 129-00037: T129-25574-00037

### A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(15)]

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

(a) One (1) Truck loading rack, with a maximum capacity of 60,000 gallons of submerged loading of gasoline, kerosene or distillate oil per hour, installed in 1958, identified as Loading Rack, and exhausting to stack 65; controlled by the Loading Rack Flare, equipped with a 0.09 million British Thermal Units per hour (mmBtu/hr) natural gas fired pilot and designed to handle 160 actual cubic feet per minute (acfm) of hydrocarbon vapors, installed in 1998, and exhausting to stack 1D. Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9;

(c) One (1) FCCU regenerator, identified as 500V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10. Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(d) The following storage vessels:

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 1 | fixed roof cone tank | 404,418 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 075; |
| 2 | fixed roof cone tank | 404,502 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 076; |
| 3 | fixed roof cone tank | 404,334 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 077; |
| 4 | fixed roof cone tank | 118,272 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 018; |
| 5 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 019; |
| 6 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 020; |
| 7 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 078; |
| 8 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 079; |
| 9 | fixed roof cone tank | 204,204 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 023; |
| 10 | fixed roof cone tank | 121,590 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 024; |
| 11A | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 080; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 11B | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 081; |
| 12 | fixed roof cone tank | 6,090 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 082; |
| 15 | fixed roof cone tank | 24,654 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 083; |
| 17 | fixed roof cone tank | 997,584 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 030; |
| 18 | internal floating roof tank/mechanical primary seal | 1,052,013 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2003 | 40 CFR Part 60, Subpart Kb | 037; |
| 19 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 616,938 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 032; |
| 21 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,002,750 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 034; |
| 22A | fixed roof cone tank | 1,050,000 | 84,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure No. 2 fuel oil | 2003 | 40 CFR 63, Subpart CC | 120; |
| 22B | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 127; |
| 24 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 588,714 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1985 | 40 CFR Part 60, Subpart Kb | 037; |
| 25 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 656,614 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 038; |
| 26 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,006,068 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 039; |
| 33 | fixed roof cone tank | 2,262,960 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 085; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 34 | fixed roof cone tank | 984,480 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 045; |
| 35 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 997,962 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate, | 1946 | - | 046; |
| 36 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,261,954 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of jet kerosene, | 1946 | - | 047; |
| 37 | fixed roof cone tank | 2,247,126 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 048; |
| 38 | fixed roof cone tank | 2,248,386 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 049;; |
| 39 | fixed roof cone tank | 2,250,234 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 050; |
| 40 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,222,388 | 336,000 | RVP 15 Gasoline, | 1949 | - | 051; |
| 41 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,204,244 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1949 | - | 052; |
| 42 | fixed roof cone tank | 2,261,574 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1950 | - | 053; |
| 43 | fixed roof cone tank | 2,254,098 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1951 | - | 054; |
| 44 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 055; |
| 45 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 056; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 46 | fixed roof cone tank/mechanical primary seal | 3,402,000 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of distillate, | 1955 | - | 057; |
| 47 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 5,040,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1976 | 40 CFR Part 60, Subpart K | 058; |
| 48 | fixed roof cone tank/external floating roof tank/ mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 059; |
| 49 | fixed roof cone tank/ external floating roof tank/ mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 060; |
| 50 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,934,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1965 | - | 061; |
| 51 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,937,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1973 | - | 062; |
| 52 | fixed roof cone tank | 3,935,148 | 336,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1976 | 40 CFR Part 60, Subpart K | 063; |
| 53 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 086; |
| 54 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 087; |
| 55 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 088; |
| 56 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 089; |
| 58 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1980 | - | 102; |
| 159 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 103; |
| 160 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 104; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 161 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 105; |
| 162 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 106; |
| 163 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 107; |
| 164 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 108; |
| 165 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 109; |
| 166 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 110; |
| 167 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 111; |
| 168 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 112; |
| 169 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1989 | - | 113; |
| 125 | fixed roof cone tank | 157,000 | 6,000 | hydrocarbon with vapor pressure of No.2 fuel oil or less | 2005 | - | 015; |
| 173 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 128; |
| 174 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2007 | - | 129 |
| 175 | fixed roof cone tank/internal floating roof tank/liquid mounted primary seal | 2,310,000 | 210,000 | Petroleum with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2008 | 40 CFR Part 60, Subpart Kb | 130 |

(e) One (1) Main Refinery Flare, identified as 700-V101 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118;

Under 40 CFR Part 60, Subpart Ja, the Main Refinery Flare is considered an affected facility.

(f) One (1) Crude heater equipped with a Low-NOx burner, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1;

(g) One (1) Unifiner heater, identified as 400-H5 with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2;

(h) One (1) Cycle oil heater, identified as H-H2 with a maximum heat input rate of 10 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 3;

(i) One (1) Naphtha splitter heater, identified as 900-H1 with a maximum heat input rate of 12.2 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 4;

(j) One (1) Vacuum heater, identified as 200-H4 with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5;

(k) One (1) Old Platformer heater, identified as Naptha Splitter Reboiler 900-H2 with a maximum heat input rate of 27 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6;

(l) One (1) Alkylation unit heater, identified as 100-H1 with a maximum heat input rate of 13.2 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1966 and exhausting to stack 7;

(m) One (1) Auxiliary crude heater, identified as 200-H1 with a maximum heat input rate of 10.1 mmBtu/hr, combusting refinery fuel gas, installed in 1966 and exhausting to stack 11;

(n) One (1) Platformer stabilizer reb, identified as 300-H4 with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;

(o) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;

(p) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;

(q) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;

(r) One (1) Vacuum heater husky, identified as 200-H3 with a maximum heat input rate of 6.27 mmBtu/hr, combusting refinery fuel gas No. 6 residual fuel oil, installed in 1963 and exhausting to stack 64;

(s) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74. Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071. Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) one (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(v) Pipeline Valves - Gas, identified as 090. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094. Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095. Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ff) Drains, identified as 100.

(gg) Vessel Relief Valves, identified as 101. Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(hh) Cooling Towers, identified as 119; and

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery.

(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122, constructed in 2005.

(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 constructed in 2005.

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (SRU Burner 520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1, constructed in 2005.

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (Clause Furnace 520-H-102), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and

exhausting through one (1) stack identified as 124-2, constructed in 2005. In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3, constructed in 2005.

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4, constructed in 2005.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.

(1) pipeline Valves - Gas, identified as 090;
(2) pipeline Valves - Light Liquid, identified as 091;
(3) pipeline Valves - Heavy Liquid, identified as 092;
(4) pipeline Valves - Hydrogen, identified as 093;
(5) open Ended Valves, identified as 094;
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.

(oo) One (1) boiler identified as B4, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler identified as boiler B4 above is considered an affected facility.

Under the Standards of Performance for Petroleum Refineries (40 CFR Part 60, Subpart J), the boiler identified as boiler B4 above, is considered an affected facility.

(pp) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGG, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61 Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(15)]

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

(a) Metal and related material cutting, fabricating and preparation. [326 IAC 6-3]

(b) Sand blasting or mechanical stripping on tanks and other equipment. [326 IAC 6-3]

(c) Painting on tanks and other equipment. [326 IAC 6-3]

(d) Welding/Cutting of metal for vessel, pipeline and equipment maintenance. [326 IAC 6-3]

A.5 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).

## 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(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

(a) This permit, T117-23297-00014, 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 13-15-5-3. 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 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

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

(i) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(34), and

(ii) the certification is 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(34).

B.9 Annual Compliance Certification [326 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 V
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(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)][326 IAC 2-7-6(1) and (6)][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(34).

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(34).

(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 and Southeast 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.
Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058.

(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(34).

(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)(9) 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 T117-23297-00014 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(34).

(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(40). 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(34).

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] [40 CFR 72]

(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(34).

(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),(c), or (e) 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 V
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),(c), or (e). 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), (c)(1), and (e)(2).

(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(36)) 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(34).

(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(9). 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 $SO_2$ or $NO_X$ under 326 IAC 21 or 326 IAC 10-4.

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(34).

(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(16)] [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 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(2).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(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(34).

(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.7 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(34).

(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(34).

(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.8 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.9 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

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 or of initial start-up, whichever is later, 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 or the date of initial startup, whichever is later, 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
Indianapolis, Indiana 46204-2251

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(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

C.10 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment.

(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

C.11 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment.

(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup CEMS shall be brought online within four (4) hours of shutdown of the primary CEMS, and shall be operated until such time as the primary CEMS is back in operation.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 63.1572 (b).

C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60, Appendix B, 40 CFR 63, or other approved methods as specified in this permit.

C.13 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.

(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.14 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.15 Risk Management Plan [326 IAC 2-7-5(12)] [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.16 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); or

(3) 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.17 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(34).

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

C.18 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(32) ("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
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

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(34).

C.19 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

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

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. 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(34). 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.

**Stratospheric Ozone Protection**

C.21 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

Facility Description [326 IAC 2-7-5(15)]:

(a) one (1) Truck loading rack, with a maximum capacity of 60,000 gallons of submerged loading of gasoline, kerosene or distillate oil per hour, installed in 1958, identified as Loading Rack, and exhausting to stack 65; controlled by the Loading Rack Flare, equipped with a 0.09 million British Thermal Units per hour (mmBtu/hr) natural gas fired pilot and designed to handle 160 actual cubic feet per minute (acfm) of hydrocarbon vapors, installed in 1998, and exhausting to stack 1D. Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

(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 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan is required for the Truck loading rack, identified as Loading Rack 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.

**SECTION D.2 FACILITY OPERATION CONDITIONS**
**Facility Description [326 IAC 2-7-5(15)]:**

(c) One (1) FCCU regenerator, identified as 500V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(s) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74. Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122, constructed in 2005.

(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123, constructed in 2005.

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (SRU Burner 520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (Clause Furnace 520-H-102), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2, constructed in 2005. In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3, constructed in 2005.

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4, constructed in 2005.

(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.

(qq) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGG, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61 Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

(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.2.1 Particulate Matter (PM) [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emissions Limitations), particulate emissions from the 5.985 MMBtu/hr LSG Charge Reactor Heater shall not exceed Pt. This limitation is calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Pt = Pounds of particulate matter emitted per million Btu (lb/MMBtu) heat input.
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input. (Q > 10,000 MMBtu)

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), for Q > 10,000 MMBtu, Pt shall not exceed 0.1. Therefore, particulate emissions from the 5.985 MMBtu/hr LSG Charge Reactor Heater shall be limited to 0.1 pounds per MMBtu heat input.

D.2.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan is required for the CCR platformer heater, identified as 300 - H1, H2, H3, FCCU regenerator, identified as 500V-5, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), Low Sulfur Gasoline Unit (LSG), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

## SECTION D.3 FACILITY OPERATION CONDITIONS

**Facility Description [326 IAC 2-7-5(15)]:**

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 1 | fixed roof cone tank | 404,418 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 075; |
| 2 | fixed roof cone tank | 404,502 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 076; |
| 3 | fixed roof cone tank | 404,334 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 077; |
| 4 | fixed roof cone tank | 118,272 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 018; |
| 5 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 019; |
| 6 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 020; |
| 7 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 078; |
| 8 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 079; |
| 9 | fixed roof cone tank | 204,204 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 023; |
| 10 | fixed roof cone tank | 121,590 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 024; |
| 11A | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 080; |
| 11B | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 081; |
| 12 | fixed roof cone tank | 6,090 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 082; |
| 15 | fixed roof cone tank | 24,654 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 083; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 17 | fixed roof cone tank | 997,584 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 030; |
| 18 | internal floating roof tank/mechanical primary seal | 1,052,013 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2003 | 40 CFR Part 60, Subpart Kb | 037; |
| 19 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 616,938 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 032; |
| 21 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,002,750 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 034; |
| 22A | fixed roof cone tank | 1,050,000 | 84,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure No. 2 fuel oil | 2003 | 40 CFR 63, Subpart CC | 120; |
| 22B | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 127; |
| 24 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 588,714 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1985 | 40 CFR Part 60, Subpart Kb | 037; |
| 25 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 656,614 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 038; |
| 26 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,006,068 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 039; |
| 33 | fixed roof cone tank | 2,262,960 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 085; |
| 34 | fixed roof cone tank | 984,480 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 045; |
| 35 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 997,962 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate, | 1946 | - | 046; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 36 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,261,954 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of jet kerosene, | 1946 | - | 047; |
| 37 | fixed roof cone tank | 2,247,126 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 048; |
| 38 | fixed roof cone tank | 2,248,386 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 049;; |
| 39 | fixed roof cone tank | 2,250,234 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 050; |
| 40 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,222,388 | 336,000 | RVP 15 Gasoline, | 1949 | - | 051; |
| 41 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,204,244 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1949 | - | 052; |
| 42 | fixed roof cone tank | 2,261,574 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1950 | - | 053; |
| 43 | fixed roof cone tank | 2,254,098 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1951 | - | 054; |
| 44 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 055; |
| 45 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 056; |
| 46 | fixed roof cone tank/mechanical primary seal | 3,402,000 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of distillate, | 1955 | - | 057; |
| 47 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 5,040,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1976 | 40 CFR Part 60, Subpart K | 058; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 48 | fixed roof cone tank/external floating roof tank/ mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 059; |
| 49 | fixed roof cone tank/ external floating roof tank/ mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 060; |
| 50 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,934,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1965 | - | 061; |
| 51 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,937,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1973 | - | 062; |
| 52 | fixed roof cone tank | 3,935,148 | 336,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1976 | 40 CFR Part 60, Subpart K | 063; |
| 53 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 086; |
| 54 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 087; |
| 55 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 088; |
| 56 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 089; |
| 58 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1980 | - | 102; |
| 159 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 103; |
| 160 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 104; |
| 161 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 105; |
| 162 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 106; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 163 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 107; |
| 164 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 108; |
| 165 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 109; |
| 166 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 110; |
| 167 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 111; |
| 168 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 112; |
| 169 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1989 | - | 113; |
| 125 | fixed roof cone tank | 157,000 | 6,000 | hydrocarbon with vapor pressure of No.2 fuel oil or less | 2005 | - | 015; |
| 173 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 128; |
| 174 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2007 | - | 129 |
| 175 | fixed roof cone tank/internal floating roof tank/liquid mounted primary seal | 2,310,000 | 210,000 | Petroleum with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2008 | 40 CFR Part 60, Subpart Kb | 130 |

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

D.3.1 Volatile Organic Compounds (VOC) [326 IAC 8-4-3]

Pursuant to 326 IAC 8-4-3, Tank Nos. 18, 22A, 24, and 175 are subject to the following:

(a) The facility must be equipped with an internal floating roof equipped with a closure seal, or seals, to close the space between the roof edge and tank wall unless the source has been equipped with equally effective alternative control which has been approved.

(b) The facility is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials.

(c) All openings, except stub drains, are equipped with covers, lids, or seals such that:

(1) the cover, lid, or seal is in the closed position at all times except when in actual use;

(2) automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;

(3) rim vents, if provided are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

D.3.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

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

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

D.3.3 Record Keeping Requirements [326 IAC 8-4-3]

(a) The Permittee shall comply with the record keeping requirements of 326 IAC 8-4-3. The following records are required for tank Nos. 18, 22A, 24, and 175:

(1) The types of volatile petroleum liquids stored,
(2) The maximum true vapor pressure of the liquids stored, and
(3) The results of the inspections performed on the tanks.

Such records will be maintained for a period of two (2) years and shall be made available to the commissioner upon written request.

(b) Section C - General Record Keeping Requirements, of this permit contains the Permittee's obligations with regard to the records required by this condition.

**SECTION D.4 FACILITY OPERATION CONDITIONS**
**Facility Description [326 IAC 2-7-5(15)]:**

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071. Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) One (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(v) Pipeline Valves - Gas, identified as 090. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094. Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095. Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ff) Drains, identified as 100.

(gg) Vessel Relief Valves, identified as 101. Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(hh) Cooling Towers, identified as 119.

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.

(1) pipeline Valves - Gas, identified as 090.
(2) pipeline Valves - Light Liquid, identified as 091.
(3) pipeline Valves - Heavy Liquid, identified as 092.
(4) pipeline Valves - Hydrogen, identified as 093.

(5) open Ended Valves, identified as 094.
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073.
(7) flanges, identified as 095.
(8) pump Seals Light Liquid, identified as 096.
(9) pump Seals Heavy Liquid, identified as 097.
(10) compressor Seals - Gas, identified as 098.
(11) compressor Seals - Heavy Liquid, identified as 099.
(12) drains, identified as 100.
(13) vessel Relief Valves, identified as 101.
(14) cooling Towers, identified as 119.

(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.4.1 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan is required for the two (2) sets of oil/water separators, all pipeline valves, open ended valves, flanges, pump seals, compressor seals, vessel relief valves, the Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit, and Tail Gas Treatment Unit and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

**SECTION D.5 FACILITY OPERATION CONDITIONS**
**Facility Description [326 IAC 2-7-5(15)]:**

(e) One (1) Main Refinery Flare, identified as 700V-101 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118. Under 40 CFR Part 60, Subpart Ja, the Main Refinery Flare is considered an affected facility.

(f) One (1) Crude heater equipped with a Low-NOx burner, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1.

(g) One (1) Unifiner heater, identified as 400-H5 with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2.

(h) One (1) Cycle oil heater, identified as H-H2 with a maximum heat input rate of 10 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 3.

(i) One (1) Naphtha splitter heater, identified as 900-H1 with a maximum heat input rate of 12.2 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 4.

(j) One (1) Vacuum heater, identified as 200-H4 with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, approved to be modified in 2007, and exhausting to stack 5.

(k) One (1) Old Platformer heater, identified as Naptha Splitter Reboiler 900-H2 with a maximum heat input rate of 27 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6.

(l) One (1) Alkylation unit heater, identified as 100-H1 with a maximum heat input rate of 13.2 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1966 and exhausting to stack 7.

(m) One (1) Auxiliary crude heater, identified as 200-H1 with a maximum heat input rate of 10.1 mmBtu/hr, combusting refinery fuel gas, installed in 1966 and exhausting to stack 11;

(n) One (1) Platformer stabilizer , identified as 300-H4 with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;

(o) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;

(p) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;

(q) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;

(r) One (1) Vacuum heater husky, identified as 200-H3 with a maximum heat input rate of 6.27 mmBtu/hr, combusting refinery fuel gas No. 6 residual fuel oil, installed in 1963 and exhausting to stack 64.

(s) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9.

(oo) One (1) boiler identified as B4, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131. Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler B4, is considered 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.5.1 Particulate Matter (PM) [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Matter Emission Limitations for Sources of Indirect Heating), the PM emissions from boilers B1, B2 and B3 shall be limited to 0.40, 0.25 and 0.40 pounds per MMBtu heat input, respectively.

This limitation is based on the following equation:

$$P_T = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where: C = maximum ground level concentration (50 µg/m3, for a period not to exceed 60 min.)
Pt = maximum allowable particulate matter (PM) emitted per MMBtu heat input
Q = total source max. indirect heater input

N = Number of stacks in fuel burning operation.

a = plume rise factor (0.67, for Q < 1,000)

h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent "N" stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows:

$$h = \frac{\sum_{i=1}^{N} H_i \times pa_i \times Q}{\sum_{i=1}^{N} pa_i \times Q}$$

Where: pa = the actual controlled emission rate in lb/mmBtu using the emission factor from AP-42 or stack test data.

D.5.2 Particulate Matter (PM) [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Matter Emissions Limitations), particulate emissions from the one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, shall be limited to 0.25 lb/MMBtu based on the following equation :

$Pt = 1.09 / Q^{0.26}$ where: Pt = pounds of PM emitted per MMBtu heat input (lb/MMBtu)
Q = total source operating capacity (MMBtu/hr) = 253.9

D.5.3 Sulfur Dioxide ($SO_2$) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-1.1 ($SO_2$ Emissions Limitations) the $SO_2$ emissions from the emission units C-II, boilers Nos. 1, 2 and 3, 200-H4, A-HI, H101, and V-III, when burning No. 6 residual fuel oil, shall not exceed 1.6 pounds per MMBtu heat input.

(b) Pursuant to 326 IAC 7-1.1 ($SO_2$ Emissions Limitations) the $SO_2$ emissions from the boiler B4, when burning No. 6 residual fuel oil, shall not exceed 1.6 pounds per MMBtu heat input.

D.5.4 PSD Minor Limit [326 IAC 2-2]

(a) Pursuant to Significant Permit Modification (129-20112-00003), issued on March 21, 2005 and as revised by Significant Permit Modification (129-23090-00003), the input of No. 6 fuel oil to the four (4) boilers B1, B2, B3, and B4 with a maximum fuel oil sulfur content of 0.8 percent, shall be limited to 3,214.92 thousand gallons per twelve (12) consecutive month period with

compliance determined at the end of each month. This usage limit is required to limit the $PM_{10}$ emissions from the boilers to less than 14.49 tons per twelve (12) consecutive month period. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

(b) Pursuant to Significant Permit Modification (129-23090-00003), issued on January 30, 2007, the input of No. 6 fuel oil to Boiler B4 shall be limited to less than 730,000 gallons (with maximum fuel oil sulfur content of 0.5%) per twelve (12) consecutive month period, with compliance determined at the end of each month. This fuel oil usage limit for boiler B4 is part of the total fuel oil usage limit of 3,214.92 thousand gallons per year for all four (4) boilers (B1, B2, B3 and B4). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

D.5.5 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan is required for the one (1) Main Refinery Flare, identified as 700-V101, one (1) Crude heater equipped with a Low-NOx burner, identified as C-II, one (1) Unifiner heater, identified as 400-H5, one (1) Cycle oil heater, identified as H-H2, one (1) Naphtha splitter heater, identified as 900-H1, one (1) Vacuum heater, identified as 200-H4, one (1) Old Platformer heater, identified as Naptha S;litter Reboiler 900-H2, one (1) Alkylation unit heater, identified as 100-H1, one (1) Auxiliary crude heater, identified as 200-H1, one (1) Platformer stabilizer , identified as 300-H4, four (4) boilers, identified as B1, B2, B3, B4, one (1) Vacuum heater husky, identified as 200-H3, One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101,-and their 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**

D.5.6 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.5.3 shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed 1.6 pound per million Btu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification, or;

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.
(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and
(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the boiler using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

**Compliance Monitoring Requirements [326 IAC 2-5.1-3(e)(2)] [ 326 IAC 2-6.1-5(a)(2)]**

D.5.7 Visible Emissions Notations

(a) Visible emission notations of the boiler stacks (B1, B2, B3, and B4) exhaust shall be performed once per day during normal daylight operations while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

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

D.5.8 Record Keeping Requirements

(a) To document the compliance status with Conditions D.5.3 and D.5.4, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;
(2) Actual No. 6 residual fuel oil usage per month since last compliance determination period and equivalent $SO_2$ emissions;
(3) A certification, signed by the Permittee, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications.
(5) The name of the fuel supplier; and
(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document the compliance status with Condition D.5.5, the Permittee shall maintain daily records of visible emission notations of the four boiler stacks (B1, B2, B3, and B4) once per day or maintain a record of the reason why the visible emission notations were not taken.

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

D.5.9 Reporting Requirements

(a) A quarterly summary of the information to document compliance with Condition D.5.4 shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

**SECTION D.6 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

The following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Metal and related material cutting, fabricating and preparation. [326 IAC 6-3]

(b) Sand blasting or mechanical stripping on tanks and other equipment. [326 IAC 6-3]

(c) Painting on tanks and other equipment. [326 IAC 6-3]

(d) Welding/Cutting of metal for vessel, pipeline and equipment maintenance. [326 IAC 6-3]

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

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

D.6.1 Particulate Matter Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) pounds per hour [326 IAC 6-3-2(c)]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) the particulate emissions from the equipment listed under insignificant activities shall be limited by the following:

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

## SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

**Emissions Unit Description:**

(b) one (1) Truck loading rack, with a maximum capacity of 60,000 gallons of submerged loading of gasoline, kerosene or distillate oil per hour, installed in 1958, identified as Loading Rack, and exhausting to stack 65; controlled by the Loading Rack Flare, equipped with a 0.09 million British Thermal Units per hour (mmBtu/hr) natural gas fired pilot and designed to handle 160 actual cubic feet per minute (acfm) of hydrocarbon vapors, installed in 1998, and exhausting to stack 1D; Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

(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)]**

E.1.1 General Provisions Relating to NESHAP [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

The provisions of 40 CFR Part 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 Table 1 of 40 CFR Part 63, Subpart R.

E.1.2 Gasoline Distribution Facilities NESHAP [326 IAC 20-10-1] [40 CFR 63, Subpart R]

The Permittee shall comply with the provisions of 40 CFR 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities, which are incorporated by reference as 326 IAC 20-10-1, apply to the truck loading rack and flare. This rule is included as Attachment A. This source is subject to the following requirements of 40 CFR Part 63, Subpart R:

(1) 40 CFR Part 63.420
(2) 40 CFR Part 63.421
(3) 40 CFR Part 63.422(a-c)
(4) 40 CFR Part 63.424
(5) 40 CFR Part 63.425(a-c), (e-h)
(6) 40 CFR Part 63.427(a-b)
(7) 40 CFR Part 63.428(b), (c), (e), (f), (g), (h)(1-3), (i), (j), (k)
(8) Table 1.

**SECTION E.2 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

(c) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(s) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74; Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(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)]**

E.2.1 General Provisions Relating to NESHAP [326 IAC 20-1-1] [40 CFR 63, Subpart A]

The provisions of 40 CFR Part 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 Table 1 of 40 CFR Part 63, Subpart UUU.

E.2.2 National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units [40 CFR Part 63, Subpart UUU] [326 IAC 20-50-1]

The Permittee shall comply with the provisions of 40 CFR 63, Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, which are incorporated by reference as 326 IAC 20-50-1, apply to the associated process vents and bypass lines. This rule is included as Attachment B. This source is subject to the following requirements of 40 CFR Part 63, Subpart UUU:

(1) 40 CFR 63.1560
(2) 40 CFR 63.1561
(3) 40 CFR 63.1562
(4) 40 CFR 63.1563(b), (c)1, 2i-iv, (e)
(5) 40 CFR 63.1564
(6) 40 CFR 63.1565
(7) 40 CFR 63.1566
(8) 40 CFR 63.1567
(9) 40 CFR 63.1568
(10) 40 CFR 63.1569
(11) 40 CFR 63.1570
(12) 40 CFR 63.1571

(13) 40 CFR 63.1572
(14) 40 CFR 63.1573
(15) 40 CFR 63.1574
(16) 40 CFR 63.1575
(17) 40 CFR 63.1576
(18) 40 CFR 63.1577
(19) 40 CFR 63.1578
(20) 40 CFR 63.1579
(21) Tables 1-44

**SECTION E.3 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122, constructed in 2005.

(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 constructed in 2005.

(ll)

(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1, constructed in 2005.

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2, constructed in 2005. In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Petroleum Refineries NSPS (40 CFR 60, Subpart J), the boiler B4, is considered a new source.

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

E.3.1 General Provisions Relating to NSPS [326 IAC 12-1-1] [40 CFR 60, Subpart J]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart J.

E.3.2 Standards of Performance for Petroleum Refineries [40 CFR Part 60, Subpart J] [326 IAC 12]

The Permittee shall comply with the provisions of 40 CFR 60, Subpart J - Standards of Performance for Petroleum Refineries, which are incorporated by reference as 326 IAC 12-1-1. This rule is included as Attachment H. This source is subject to the following requirements of 40 CFR Part 60, Subpart J:

(1) 40 CFR 60.100
(2) 40 CFR 60.101
(3) 40 CFR 60.104(a)(1)
(4) 40 CFR 60.105(a), (b), (e)(3)
(5) 40 CFR 60.106(a), (e)(1)(i-iii)
(6) 40 CFR 60.107(e), (f), (g)
(7) 40 CFR 60.108(a)
(8) 40 CFR 60.109

**SECTION E.4 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

(d) The following storage vessels:

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 47 | fixed roof cone tank/internal floating roof tank,/mechanical primary seal | 5,040,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1976 | 40 CFR Part 60, Subpart K | 058; |
| 52 | fixed roof cone tank | 3,935,148 | 336,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1976 | 40 CFR Part 60, Subpart K | 063; |

(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)]**

E.4.1 General Provisions Relating to NSPS [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to the tanks as specified in Table E.3 as shown above except when otherwise specified in 40 CFR Part 60, Subpart K.

E.4.2 Standards of Performance 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 Part 60, Subpart K] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart K, the Permittee shall comply with the provisions of Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, which are incorporated by reference as 326 IAC 12-1-1, for the tanks as specified in the table above. A copy of this rule is included as Attachment I. This source is subject to the following requirements of 40 CFR Part 60, Subpart K:

(1) 40 CFR 60.110 (a-c)
(2) 40 CFR 60.111 (a-l)
(3) 40 CFR 60.112 (a)
(4) 40 CFR 60.113 (a)

## SECTION E.5 FACILITY OPERATION CONDITIONS

**Facility Description [326 IAC 2-7-5(15)]:**

(d) The following storage vessels:

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 18 | internal floating roof tank/mechanical primary seal | 1,052,013 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2003 | 40 CFR Part 60, Subpart Kb | 037; |
| 24 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 588,714 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1985 | 40 CFR Part 60, Subpart Kb | 037; |
| 24 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 588,714 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1985 | 40 CFR Part 60, Subpart Kb | 037; |
| 175 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 210,000 | Petroleum with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2008 | 40 CFR Part 60, Subpart Kb | 130; |

(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)]**

E.5.1 General Provisions Relating to NSPS [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to the tanks as specified in the table above except when otherwise specified in 40 CFR Part 60, Subpart Kb.

E.5.2 Standards of Performance for VOC Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR Part 60, Subpart Kb] [326 IAC 12]

(a) Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall comply with the provisions of Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels), which are incorporated by reference as 326 IAC 12-1-1, for the tanks as specified in the table above. A copy of this rule is included as Attachment C. This source is subject to the following requirements of 40 CFR Part 60, Subpart Kb:

(1) 40 CFR 60.110b (a), (b), (d)(1-8), (e)(i-ii), (2), (3), (4)
(2) 40 CFR 60.111b
(3) 40 CFR 60.112b (a)(1(i-ix)), (4)
(4) 40 CFR 60.113b (a)(1-5), (b)(1-4)
(5) 40 CFR 60.114b (a-d)
(6) 40 CFR 60.115b (a-b)
(7) 40 CFR 60.116b (a-d)
(8) 40 CFR 60.117b (a), (b)

**SECTION E.6 FACILITY OPERATION CONDITIONS**
**Facility Description [326 IAC 2-7-5(15)]:**

The following equipment in VOC service.

(v) Pipeline Valves - Gas, identified as 090; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094; Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095; Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(gg) Vessel Relief Valves, identified as 101; Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector is considered an affected source at a petroleum refinery.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector is considered an affected source at a petroleum refinery.

(1) pipeline Valves - Gas, identified as 090.
(2) pipeline Valves - Light Liquid, identified as 091.
(3) pipeline Valves - Heavy Liquid, identified as 092.
(4) pipeline Valves - Hydrogen, identified as 093.
(5) open Ended Valves, identified as 094.
(6) flanges, identified as 095.
(7) pump Seals Light Liquid, identified as 096.
(8) pump Seals Heavy Liquid, identified as 097.
(9) compressor Seals - Gas, identified as 098.
(10) compressor Seals - Heavy Liquid, identified as 099.
(11) vessel Relief Valves, identified as 101.

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

E.6.1 General Provisions Relating to NSPS [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart GGG as an “affected facility,” except when otherwise specified in 40 CFR Part 60, Subpart GGG.

E.6.2 Standards of Performance 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 Part 60, Subpart GGG] [326 IAC 12-1-1]

(a) Pursuant to 40 CFR Part 60, Subpart GGG, the Permittee shall comply with the provisions of Standards of Performance 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 which are incorporated by reference as 326 IAC 12-1-1. A copy of this rule is included as Attachment E. This source is subject to the following requirements of 40 CFR Part 60, Subpart GGG:

(1) 40 CFR 60.590
(2) 40 CFR 60.591
(3) 40 CFR 60.592
(4) 40 CFR 60.593

**SECTION E.7 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071; Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) One (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(ff) Drains, identified as 100.

(hh) Cooling Towers, identified as 119.

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

E.7.1 General Provisions Relating to NSPS [326 IAC 12-1-1] [40 CFR Part 60, Subpart A]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated as 326 IAC 12-1-1, apply to a facility described in this section when such facility is defined in 40 CFR Part 60, Subpart QQQ as an “affected facility,” except when otherwise specified in 40 CFR Part 60, Subpart QQQ.

E.7.2 Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems [326 IAC 12-1-1][40 CFR Part 60, Subpart QQQ]

(a) Pursuant to 40 CFR Part 60, Subpart QQQ, the Permittee shall comply with the provisions of Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems which are incorporated by reference as 326 IAC 12-1-1. A copy of this rule is included as Attachment F. This source is subject to the following requirements of 40 CFR Part 60, Subpart QQQ:

(1) 40 CFR 60.690
(2) 40 CFR 60.691
(3) 40 CFR 60.692-1
(4) 40 CFR 60.692-3(a)1-5, (c)1-2, (d), (f)
(5) 40 CFR 60.692-5
(6) 40 CFR 60.692-6
(7) 40 CFR 60.692-7
(8) 40 CFR 60.693-2
(9) 40 CFR 60.696(a), (c), (d)(1)(i-iii) (2)(i-ii)
(10) 40 CFR 60.697(a), (c), (e)1-4, (k)1-2
(11) 40 CFR 60.699

**SECTION E.8 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

(1) All miscellaneous process vents from petroleum refining process units;

(2) All storage vessels associated with petroleum refining process units;

(3) All wastewater streams and treatment operations associated with petroleum refining process units;

(4) All equipment leaks from petroleum refining process units;

(5) All gasoline loading racks classified under Standard Industrial Classification code 2911;

(6) All marine vessel loading operations located at a petroleum refinery; and

(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.

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

E.8.1 General Provisions Relating to NESHAP [326 IAC 20-1-1] [40 CFR Part 63, Subpart A]

(a) The provisions of 40 CFR Part 63, Subpart A - General Provisions, which are incorporated as 326 IAC 20-1-1, apply to certain of the tanks described in this section except when otherwise specified in 40 CFR Part 63, Subpart CC.

E.8.2 National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries [326 IAC 20-16-1] [40 CFR Part 63, Subpart CC]

(a) Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, which are incorporated by reference as 326 IAC 20-16-1. A copy of this rule is included as Attachment D. This source is subject to the following requirements of 40 CFR Part 63, 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

**SECTION E.9 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]:**

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler B4, is considered a new source.

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

**New Source Performance Standards (NSPS) Requirements [326 IAC 2-8-4(1)]**

E.9.1 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facility described in this section except when otherwise specified in 40 CFR Part 60, Subpart Dc.

E.9.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of the National Source Performance Standards for Small Industrial-Commercial- Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12-1-1, for the boiler specified above. A copy of the rule is included as Attachment G. This source is subject to the following requirements of 40 CFR Part 60, Subpart Dc:

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.41c
(3) 40 CFR 60.42c(d),(e)1,(g)(h)2,(i),(j)
(4) 40 CFR 60.43c(c), (e)(1,4)
(5) 40 CFR 60.44c(a), (b), (c), (d), (g), (h)
(6) 40 CFR 60.48c(e)11,(f)2i-iv

**SECTION E.10 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]**

Under 40 CFR 61, Subpart FF, this stationary petroleum refinery is considered an affected facility.

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

E.10.1 General Provisions Relating to NESHAP Subpart FF [40 CFR Part 61, Subpart A]

The provisions of 40 CFR Part 61, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 14-1, apply to this stationary petroleum refinery except when otherwise specified in 40 CFR Part 61, Subpart FF.

E.10.2 Benzene Waste Operations NESHAP [40 CFR Part 61, Subpart FF]

Pursuant to 40 CFR Part 61, Subpart FF, the Permittee shall comply with the National Emission Standards for Benzene Waste Operations which are incorporated as reference as 326 IAC 14-1-1. A copy of this rule is included as Attachment K. This source is subject to the following requirements of 40 CFR Part 61, Subpart FF:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356(a)(b)(1),(b)(5)
(6) 40 CFR 61.357(a)(c)

**SECTION E.11 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

Each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service constructed, reconstructed, or modified after November 7, 2006.

Under 40 CFR 60, Subpart GGGa, these units are considered affected facilities at a petroleum refinery.

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

E.11.1 General Provisions Relating to NSPS Subpart GGGa [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, apply to the facility described in this section except as otherwise specified in 40 CFR Part 60, Subpart GGGa.

E.11.2 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS [40 CFR Part 60, Subpart GGGa]

Pursuant to 40 CFR Part 60, Subpart GGGa, the Permittee shall comply with the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after November 7, 2006 which are incorporated as 326 IAC 12-1-1, for the components specified above. A copy of this rule is included as Attachment J. The source is subject to the following requirements of 40 CFR Part 60, Subpart GGGa:

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a
(4) 40 CFR 60.593a

**SECTION E.12 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

(e) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 MMBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 MMBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118;

(pp) One (1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja, the Main Refinery Flare is considered an affected facility.

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

E.12.1 General Provisions Relating to NSPS Subpart Ja [40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, apply to the facility described in this section except as otherwise specified in 40 CFR Part 60, Subpart Ja.

E.12.2 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS [40 CFR Part 60, Subpart Ja (Certain Sections Currently Under Indefinite Stay)]

Pursuant to 40 CFR Part 60, Subpart Ja, the Permittee comply with the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after May 14, 2007, for the refinery flare and LSG Reactor Charge Heater specified above. A copy of this rule is included as Attachment L. The source is subject to the following requirements of 40 CFR Part 60, Subpart Ja:

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(g), (h)
(4) 40 CFR 60.103a
(5) 40 CFR 60.104a
(6) 40 CFR 60.107a
(7) 40 CFR 60.108a

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# PART 70 OPERATING PERMIT
# CERTIFICATION

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-25424-00003

**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: |

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY

**COMPLIANCE AND ENFORCEMENT BRANCH**
**100 North Senate Avenue**
**MC 61-53 IGCN 1003**
**Indianapolis, Indiana 46204-2251**
**Phone: 317-233-0178**
**Fax: 317-233-6865**

## PART 70 OPERATING PERMIT
## EMERGENCY OCCURRENCE REPORT

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-25424-00003

**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**) 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



| |
|---|
| Date/Time Emergency started: |
| Date/Time Emergency was corrected: |
| Was the facility being properly operated at the time of the emergency? Y N |
| Type of Pollutants Emitted: TSP, PM-10, $SO_2$, VOC, $NO_X$, CO, Pb, other: |
| Estimated amount of pollutant(s) emitted during emergency: |
| Describe the steps taken to mitigate the problem: |
| Describe the corrective actions/response steps taken: |
| Describe the measures taken to minimize emissions: |
| 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: |

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# COMPLIANCE DATA SECTION

## PART 70 OPERATING PERMIT
## SEMI-ANNUAL NATURAL GAS FIRED BOILER CERTIFICATION

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-25424-00003

| |
|---|
| ☐ Natural Gas Only<br>☐ Alternate Fuel burned<br>From:_____ To:_____ |

| |
|---|
| I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.<br><br>Signature: |
| Printed Name: |
| Title/Position: |
| Phone: |
| Date: |

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
# OFFICE OF AIR QUALITY
# COMPLIANCE DATA SECTION

## Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-7882-00003
Facility: Boilers B1, B2, B3, and B4
Parameter: No. 6 Fuel Oil Usage
Limit: The input of No. 6 fuel oil to the four boilers B1, B2, B3, and B4, based on a maximum fuel oil sulfur content of 0.8 percent, shall be limited to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

YEAR:

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| Month 3 | | | |

☐ 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 DATA SECTION

## Part 70 Quarterly Report

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-25424-00003
Facility: Boiler B4
Parameter: The input of No. 6 fuel oil to Boiler B4
Limit: Less than 730,000 gallons (with maximum fuel oil sulfur content of 0.5% based on the Subpart Dc) per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER : YEAR:

| Month | Column 1 | Column 2 | Column 1 + Column 2 |
|---|---|---|---|
| | This Month | Previous 11 Months | 12 Month Total |
| Month 1 | | | |
| Month 2 | | | |
| Month 3 | | | |

☐ 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 DATA SECTION
# PART 70 OPERATING PERMIT
# QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Countrymark Cooperative, LLP
Source Address: 1200 Refinery Road, Mount Vernon, Indiana 47620
Part 70 Permit No.: T129-25424-00003

**Months: _____ to _ Year: _____**



| | |
|---|---|
| This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, 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 | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |

| | |
|---|---|
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |
| **Permit Requirement** (specify permit condition #) | |
| **Date of Deviation:** | **Duration of Deviation:** |
| **Number of Deviations:** | |
| **Probable Cause of Deviation:** | |
| **Response Steps Taken:** | |

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

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# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment A
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

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

$E_T$=CF[0.59($T_F$)(1–CE)+0.17 ($T_E$)+0.08($T_{ES}$)+0.038($T_I$)+8.5×10–6(C)+KQ]+0.04(OE)

where:

$E_T$= emissions screening factor for bulk gasoline terminals;

CF=0.161 for bulk gasoline terminals and pipeline breakout stations that do not handle any reformulated or oxygenated gasoline containing 7.6 percent by volume or greater methyl tert-butyl ether (MTBE), OR

CF=1.0 for bulk gasoline terminals and pipeline breakout stations that handle reformulated or oxygenated gasoline containing 7.6 percent by volume or greater MTBE;

CE=control efficiency limitation on potential to emit for the vapor processing system used to control emissions from fixed-roof gasoline storage vessels [value should be added in decimal form (percent divided by 100)];

$T_F$= total number of fixed-roof gasoline storage vessels without an internal floating roof;

$T_E$= total number of external floating roof gasoline storage vessels with only primary seals;

$T_{ES}$= total number of external floating roof gasoline storage vessels with primary and secondary seals;

$T_I$= total number of fixed-roof gasoline storage vessels with an internal floating roof;

C = number of valves, pumps, connectors, loading arm valves, and open-ended lines in gasoline service;

Q=gasoline throughput limitation on potential to emit or gasoline throughput limit in compliance with paragraphs (c), (d), and (f) of this section (liters/day);

K = $4.52\times10^{-6}$for bulk gasoline terminals with uncontrolled loading racks (no vapor collection and processing systems), *OR*

K = $(4.5\times10^{-9})$(EF + L) for bulk gasoline terminals with controlled loading racks (loading racks that have vapor collection and processing systems installed on the emission stream);

EF=emission rate limitation on potential to emit for the gasoline cargo tank loading rack vapor processor outlet emissions (mg of total organic compounds per liter of gasoline loaded);

OE=other HAP emissions screening factor for bulk gasoline terminals or pipeline breakout stations (tons per year). OE equals the total HAP from other emission sources not specified in parameters in the equations for $E_T$or $E_P$. If the value of 0.04(OE) is greater than 5 percent of either $E_T$or $E_P$, then paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability;

L = 13 mg/l for gasoline cargo tanks meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in §60.501 of this chapter, *OR*

L = 304 mg/l for gasoline cargo tanks not meeting the requirement to satisfy the test criteria for a vapor-tight gasoline tank truck in §60.501 of this chapter; or

(2) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in §63.2 of subpart A of this part.

(b) The affected source to which the provisions of this subpart apply is each pipeline breakout station, except those pipeline breakout stations:

(1) For which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, $E_P$, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

$E_P$=CF $[6.7(T_F)(1\text{-}CE) + 0.21(T_E) + 0.093(T_{ES}) + 0.1(T_I) + 5.31\times10^{-6}(C)) + 0.04(OE)$;

where:

EP=emissions screening factor for pipeline breakout stations,

and the definitions for CF, $T_F$, CE, $T_E$, $T_{ES}$, 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, $E_T$or $E_P$, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 1.0 but greater than or equal to 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section, and approved by the Administrator, is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of §63.428(i).

(d) A facility for which the results, $E_T$or $E_P$, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

(1) Operate the facility such that none of the facility parameters used to calculate results under paragraph (a)(1) or (b)(1) of this section is exceeded in any rolling 30-day period; and

(2) Maintain records and provide reports in accordance with the provisions of §63.428(j).

(e) The provisions of paragraphs (a)(1) and (b)(1) of this section shall not be used to determine applicability to bulk gasoline terminals or pipeline breakout stations that are either:

(1) Located within a contiguous area and under common control with another bulk gasoline terminal or pipeline breakout station, or

(2) Located within a contiguous area and under common control with other sources not specified in paragraphs (a)(1) or (b)(1) of this section, that emit or have the potential to emit a hazardous air pollutant.

(f) Upon request by the Administrator, the owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of any paragraphs in this section including, but not limited to, the parameters and assumptions used in the applicable equation in paragraph (a)(1) or (b)(1) of this section, shall demonstrate compliance with those paragraphs.

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of 40 CFR part 60, subpart Kb or XX of this chapter shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility.

(h) Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station is subject to the provisions of 40 CFR part 63, subpart A—General Provisions, as indicated in Table 1.

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with subpart CC, §§63.646, 63.648, 63.649, and 63.650 is not subject to subpart R standards, except as specified in subpart CC, §63.650.

(j) *Rules Stayed for Reconsideration.* Notwithstanding any other provision of this subpart, the December 14, 1995 compliance date for existing facilities in §63.424(e) and §63.428(a), (i)(1), and (j)(1) of this subpart is stayed from December 8, 1995, to March 7, 1996.

[59 FR 64318, Dec. 14, 1994, as amended at 60 FR 43260, Aug. 18, 1995; 60 FR 62992, Dec. 8, 1995; 62 FR 9092, Feb. 28, 1997]

## § 63.421 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act; in subparts A, K, Ka, Kb, and XX of part 60 of this chapter; or in subpart A of this part. All terms defined in both subpart A of part 60 of this chapter and subpart A of this part shall have the meaning given in subpart A of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

*Bulk gasoline terminal* means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.

*Controlled loading rack,* for the purposes of §63.420, means a loading rack equipped with vapor collection and processing systems that reduce displaced vapor emissions to no more than 80 milligrams of total organic compounds per liter of gasoline loaded, as measured using the test methods and procedures in §60.503 (a) through (c) of this chapter.

*Equipment* means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in the gasoline liquid transfer and vapor collection systems. This definition also includes the entire vapor processing system except the exhaust port(s) or stack(s).

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

*Gasoline cargo tank* means a delivery tank truck or railcar which is loading gasoline or which has loaded gasoline on the immediately previous load.

*In gasoline service* means that a piece of equipment is used in a system that transfers gasoline or gasoline vapors.

*Limitation(s) on potential to emit* means limitation(s) limiting a source's potential to emit as defined in §63.2 of subpart A of this part.

*Operating parameter value* means a value for an operating or emission parameter of the vapor processing system (e.g., temperature) which, if maintained continuously by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with the applicable emission standard. The operating parameter value is determined using the procedures outlined in §63.425(b).

*Oxygenated gasoline* means the same as defined in 40 CFR 80.2(rr).

*Pipeline breakout station* means a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

*Reformulated gasoline* means the same as defined in 40 CFR 80.2(ee).

*Thermal oxidation system* means a combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures.

*Uncontrolled loading rack* means a loading rack used to load gasoline cargo tanks that is not a controlled loading rack.

*Vapor-tight gasoline cargo tank* means a gasoline cargo tank which has demonstrated within the 12 preceding months that it meets the annual certification test requirements in §63.425(e), and which is subject at all times to the test requirements in §63.425 (f), (g), and (h).

*Volatile organic liquid* (VOL) means, for the purposes of this subpart, gasoline.

[59 FR 64318, Dec. 14, 1994, as amended at 62 FR 9093, Feb. 28, 1997; 68 FR 70965, Dec. 19, 2003]

## § 63.422 Standards: Loading racks.

(a) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in §60.502 of this chapter except for paragraphs (b), (c), and (j) of that section. For purposes of this section, the term “affected facility” used in §60.502 of this chapter means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.

(b) Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with §60.502(e) of this chapter as follows:

(1) For the purposes of this section, the term “tank truck” as used in §60.502(e) of this chapter means “cargo tank.”

(2) Section 60.502(e)(5) of this chapter is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(i) The tank truck or railcar gasoline cargo tank meets the test requirements in §63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in §63.425(i);

(ii) For each gasoline cargo tank failing the test in §63.425 (f) or (g) at the facility, the cargo tank either:

(A) Before repair work is performed on the cargo tank, meets the test requirements in §63.425 (g) or (h), or

(B) After repair work is performed on the cargo tank before or during the tests in §63.425 (g) or (h), subsequently passes the annual certification test described in §63.425(e).

(d) Each owner or operator shall meet the requirements in all paragraphs of this section as expeditiously as practicable, but no later than December 15, 1997, at existing facilities and upon startup for new facilities.

(e) As an alternative to 40 CFR 60.502(h) and (i) as specified in paragraph (a) of this section, the owner or operator may comply with paragraphs (e)(1) and (2) of this section.

(1) The owner or operator shall design and operate the vapor processing system, vapor collection system, and liquid loading equipment to prevent gauge pressure in the railcar gasoline cargo tank from exceeding the applicable test limits in §63.425(e) and (i) during product loading. This level is not to be exceeded when measured by the procedures specified in 40 CFR 60.503(d) of this chapter.

(2) No pressure-vacuum vent in the bulk gasoline terminal's vapor processing system or vapor collection system may begin to open at a system pressure less than the applicable test limits in §63.425(e) or (i).

[59 FR 64318, Dec. 14, 1994; 60 FR 32913, June 26, 1995, as amended at 68 FR 70965, Dec. 19, 2003]

## § 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.

[59 FR 64318, Dec. 14, 1994, as amended at 61 FR 7723, Feb. 29, 1996]

## § 63.425 Test methods and procedures.

(a) Each owner or operator subject to the emission standard in §63.422(b) or 40 CFR 60.112b(a)(3)(ii) shall comply with the requirements in paragraphs (a)(1) and (2) of this section.

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (a)(1)(i) or (ii) of this section.

(i) Use the test methods and procedures in 40 CFR 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under 40 CFR 60.503(b), or

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in §63.7(f).

(2) The performance test requirements of 40 CFR 60.503(c) do not apply to flares defined in §63.421 and meeting the flare requirements in §63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §63.11(b) and 40 CFR 60.503(a), (b), and (d), respectively.

(b) For each performance test conducted under paragraph (a) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

(1) During the performance test, continuously record the operating parameter under §63.427(a);

(2) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

(3) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in §63.422(b) or §60.112b(a)(3)(ii) of this chapter.

(c) For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test.

(d) The owner or operator of each gasoline storage vessel subject to the provisions of §63.423 shall comply with §60.113b of this chapter. If a closed vent system and control device are used, as specified in §60.112b(a)(3) of this chapter, to comply with the requirements in §63.423, the owner or operator shall also comply with the requirements in paragraph (b) of this section.

(e) *Annual certification test.* The annual certification test for gasoline cargo tanks shall consist of the following test methods and procedures:

(1) Method 27, appendix A, 40 CFR part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure ($P_i$) for the pressure test shall be 460 mm $H_2O$ (18 in. $H_2O$), gauge. The initial vacuum ($V_i$) for the vacuum test shall be 150 mm $H_2O$ (6 in. $H_2O$), gauge. The maximum allowable pressure and vacuum changes ($\Delta$ p, $\Delta$ v) are as shown in the second column of Table 2 of this paragraph.

**Table 2—Allowable Cargo Tank Test Pressure or Vacuum Change**

| Cargo tank or | Annual certification-allowable | Allowable pressure |
|---|---|---|

| compartment capacity, liters (gal) | pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm $H_2O$ (in. $H_2O$) | change (Δ p) in 5 minutes at any time, mm $H_2O$ (in. $H_2O$) |
|---|---|---|
| 9,464 or more (2,500 or more) | 25 (1.0) | 64 (2.5) |
| 9,463 to 5,678 (2,499 to 1,500) | 38 (1.5) | 76 (3.0) |
| 5,679 to 3,785 (1,499 to 1,000) | 51 (2.0) | 89 (3.5) |
| 3,782 or less (999 or less) | 64 (2.5) | 102 (4.0) |

(2) Pressure test of the cargo tank's internal vapor valve as follows:

(i) After completing the tests under paragraph (e)(1) of this section, use the procedures in Method 27 to repressurize the tank to 460 mm $H_2O$ (18 in. $H_2O$), 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 $H_2O$ (5 in. $H_2O$).

(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 $H_2O$ (18.0 in. $H_2O$), 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 $H_2O$ (18 in. $H_20$), gauge, a fine adjust valve be used to adjust the headspace pressure to 460 mm $H_2O$ (18.0 in. $H_2O$), gauge for the next 30 ±5 seconds.

(3) Reseal the cargo tank vapor collection system and record the headspace pressure after 1 minute. The measured headspace pressure after 1 minute shall be greater than the minimum allowable final headspace pressure ($P_F$) as calculated from the following equation:

$$P_F = 18\left(\frac{(18-N)}{18}\right)^{\left(\frac{V_s}{3(V_h)}\right)}$$

where:

($P_F$) = minimum allowable final headspace pressure, in. $H_2O$, 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. $H_2O$, gauge;

N = 5-minute continuous performance standard at any time from the third column of Table 2 of §63.425(e)(i), inches $H_2O$.

(4) Conduct the internal vapor valve portion of this test by repressurizing the cargo tank headspace with nitrogen to 460 mm $H_2O$ (18 in. $H_2O$), gauge. Close the internal vapor valve(s), wait for 30 ±5 seconds, then relieve the pressure downstream of the vapor valve in the vapor collection system to atmospheric pressure. Wait 15 seconds, then reseal the vapor collection system. Measure and record the pressure every minute for 5 minutes. Within 5 seconds of the pressure measurement at the end of 5 minutes, open the vapor valve and record the headspace pressure as the “final pressure.”

(5) If the decrease in pressure in the vapor collection system is less than at least one of the interval pressure change values in Table 3 of this paragraph, or if the final pressure is equal to or greater than 20 percent of the 1-minute final headspace pressure determined in the test in paragraph (g)(3) of this section, then the cargo tank is considered to be a vapor-tight gasoline cargo tank.

**Table 3—Pressure Change for Internal Vapor Valve Test**

| Time interval | Interval pressure change, mm $H_2O$ (in. $H_2O$) |
|---|---|
| After 1 minute | 28 (1.1) |
| After 2 minutes | 56 (2.2) |
| After 3 minutes | 84 (3.3) |
| After 4 minutes | 112 (4.4) |
| After 5 minutes | 140 (5.5) |

(h) *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27, appendix A, 40 CFR Part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure ($P_i$) shall be 460 mm $H_2O$ (18 in. $H_2O$), gauge. The maximum allowable 5-minute pressure change ($\Delta$ p) which shall be met at any time is shown in the third column of Table 2 of §63.425(e)(1).

(i) *Railcar bubble leak test procedures.* As an alternative to paragraph (e) of this section for annual certification leakage testing of gasoline cargo tanks, the owner or operator may comply with paragraphs (i)(1) and (2) of this section for railcar gasoline cargo tanks, provided the railcar tank meets the requirement in paragraph (i)(3) of this section.

(1) Comply with the requirements of 49 CFR 173.31(d), 179.7, 180.509, and 180.511 for the testing of railcar gasoline cargo tanks.

(2) The leakage pressure test procedure required under 49 CFR 180.509(j) and used to show no indication of leakage under 49 CFR 180.511(f) shall be ASTM E 515–95 (incorporated by reference, *see* §63.14), BS EN 1593:1999 (incorporated by reference, *see* §63.14), or another bubble leak test procedure meeting the requirements in 49 CFR 179.7, 180.505, and 180.509.

(3) The alternative requirements in this paragraph (i) may not be used for any railcar gasoline cargo tank that collects gasoline vapors from a vapor balance system permitted under or required by a Federal, State, local, or tribal agency. A vapor balance system is a piping and collection system designed to collect gasoline vapors displaced from a storage vessel, barge, or other container being loaded, and routes the displaced gasoline vapors into the railcar gasoline cargo tank from which liquid gasoline is being unloaded.

[59 FR 64318, Dec. 14, 1994; 60 FR 7627, Feb. 8, 1995; 60 FR 32913, June 26, 1995; 68 FR 70965, Dec. 19, 2003]

### § 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.

[59 FR 46350, Sept. 8, 1994, as amended at 68 FR 70966, Dec. 19, 2003]

## § 63.428 Reporting and recordkeeping.

(a) The initial notifications required for existing affected sources under §63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by December 16, 1996, whichever is later. Affected sources that are major sources on December 16, 1996 and plan to be area sources by December 15, 1997 shall include in this notification a brief, non-binding description of and schedule for the action(s) that are planned to achieve area source status.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as follows:

(1) Annual certification testing performed under §63.425(e) and railcar bubble leak testing performed under §63.425(i); and

(2) Continuous performance testing performed at any time at that facility under §63.425 (f), (g), and (h).

(3) The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:

(i) Name of test: Annual Certification Test—Method 27 (§63.425(e)(1)); Annual Certification Test—Internal Vapor Valve (§63.425(e)(2)); Leak Detection Test (§63.425(f)); Nitrogen Pressure Decay Field Test (§63.425(g)); Continuous Performance Pressure Decay Test (§63.425(h)); or Railcar Bubble Leak Test Procedure (§63.425(i)).

(ii) Cargo tank owner's name and address.

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

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

(vii) Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.

(viii) Test results: test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:

(1) Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.427(a). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.

(2) Record and report simultaneously with the notification of compliance status required under §63.9(h):

(i) All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.425(b); and

(ii) The following information when using a flare under provisions of §63.11(b) to comply with §63.422(b):

(A) Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and

(B) All visible emissions readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.425(a).

(3) If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.427(a), the owner or operator shall submit a description of planned reporting and recordkeeping procedures. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application.

(d) Each owner or operator of storage vessels subject to the provisions of this subpart shall keep records and furnish reports as specified in §60.115b of this chapter, except records shall be kept for at least 5 years.

(e) Each owner or operator complying with the provisions of §63.424 (a) through (d) shall record the following information in the log book for each leak that is detected:

(1) The equipment type and identification number;

(2) The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell);

(3) The date the leak was detected and the date of each attempt to repair the leak;

(4) Repair methods applied in each attempt to repair the leak;

(5) “Repair delayed” and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak;

(6) The expected date of successful repair of the leak if the leak is not repaired within 15 days; and

(7) The date of successful repair of the leak.

(f) Each owner or operator subject to the provisions of §63.424 shall report to the Administrator a description of the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under §63.424(f), the report shall contain a full description of the program.

(1) In the case of an existing source or a new source that has an initial startup date before the effective date, the report shall be submitted with the notification of compliance status required under §63.9(h), unless an extension of compliance is granted under §63.6(i). If an extension of compliance is granted, the report shall be submitted on a date scheduled by the Administrator.

(2) In the case of new sources that did not have an initial startup date before the effective date, the report shall be submitted with the application for approval of construction, as described in §63.5(d).

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual report to the Administrator the following information, as applicable:

(1) Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility;

(2) Periodic reports required under paragraph (d) of this section; and

(3) The number of equipment leaks not repaired within 5 days after detection.

(h) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with §63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

(1) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.425(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(2) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

(3) Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.422(c)(2).

(4) For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:

(i) The date on which the leak was detected;

(ii) The date of each attempt to repair the leak;

(iii) The reasons for the delay of repair; and

(iv) The date of successful repair.

(i) Each owner or operator of a facility meeting the criteria in §63.420(c) shall perform the requirements of this paragraph (i), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 16, 1996 for existing facilities, within 30 days for existing facilities subject to §63.420(c) after December 16, 1996, or at startup for new facilities the methods, procedures, and assumptions supporting the calculations for determining criteria in §63.420(c);

(2) Maintain records to document that the facility parameters established under §63.420(c) have not been exceeded; and

(3) Report annually to the Administrator that the facility parameters established under §63.420(c) have not been exceeded.

(4) At any time following the notification required under paragraph (i)(1) of this section and approval by the Administrator of the facility parameters, and prior to any of the parameters being exceeded, the owner or operator may submit a report to request modification of any facility parameter to the Administrator for approval. Each such request shall document any expected HAP emission change resulting from the change in parameter.

(j) Each owner or operator of a facility meeting the criteria in §63.420(d) shall perform the requirements of this paragraph (j), all of which will be available for public inspection:

(1) Document and report to the Administrator not later than December 16, 1996 for existing facilities, within 30 days for existing facilities subject to §63.420(d) after December 16, 1996, or at startup for new facilities the use of the emission screening equations in §63.420(a)(1) or (b)(1) and the calculated value of $E_T$or $E_P$;

(2) Maintain a record of the calculations in §63.420 (a)(1) or (b)(1), including methods, procedures, and assumptions supporting the calculations for determining criteria in §63.420(d); and

(3) At any time following the notification required under paragraph (j)(1) of this section, and prior to any of the parameters being exceeded, the owner or operator may notify the Administrator of modifications to the facility parameters. Each such notification shall document any expected HAP emission change resulting from the change in parameter.

(k) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraph (b) of this section, an owner or operator may comply with the requirements in either paragraph (k)(1) or (2) of this section.

(1) An electronic copy of each record is instantly available at the terminal.

(i) The copy of each record in paragraph (k)(1) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(1) of this section.

(2) For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading ( *e.g.,* via a card lock-out system), a copy of the documentation is made available ( *e.g.,* via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.

(i) The copy of each record in paragraph (k)(2) of this section is an exact duplicate image of the original paper record with certifying signatures.

(ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (k)(2) of this section.

[59 FR 64318, Dec. 14, 1994, as amended at 61 FR 7723, Feb. 29, 1996; 62 FR 9093, Feb. 28, 1997; 68 FR 70966, Dec. 19, 2003; 71 FR 17358, Apr. 6, 2006]

### § 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

| Reference | Applies to subpart R | Comment |
|---|---|---|
| 63.1(a)(1) | Yes | |
| 63.1(a)(2) | Yes | |
| 63.1(a)(3) | Yes | |
| 63.1(a)(4) | Yes | |
| 63.1(a)(5) | No | Section reserved |
| 63.1(a)(6)(8) | Yes | |

| | | |
|---|---|---|
| 63.1(a)(9) | No | Section reserved |
| 63.1(a)(10) | Yes | |
| 63.1(a)(11) | Yes | |
| 63.1(a)(12))–(a)(14) | Yes | |
| 63.1(b)(1) | No | Subpart R specifies applicability in §63.420 |
| 63.1(b)(2) | Yes | |
| 63.1(b)(3) | No | Subpart R specifies reporting and recordkeeping for some large area sources in §63.428 |
| 63.1(c)(1) | Yes | |
| 63.1(c)(2) | Yes | Some small sources are not subject to subpart R |
| 63.1(c)(3) | No | Section reserved |
| 63.1(c)(4) | Yes | |
| 63.1(c)(5) | Yes | |
| 63.1(d) | No | Section reserved |
| 63.1(e) | Yes | |
| 63.2 | Yes | Additional definitions in §63.421 |
| 63.3(a)–(c) | Yes | |
| 63.4(a)(1)–(a)(3) | Yes | |
| 63.4(a)(4) | No | Section reserved |
| 63.4(a)(5) | Yes | |
| 63.4(b) | Yes | |
| 63.4(c) | Yes | |
| 63.5(a)(1) | Yes | |
| 63.5(a)(2) | Yes | |
| 63.5(b)(1) | Yes | |
| 63.5(b)(2) | No | Section reserved |
| 63.5(b)(3) | Yes | |
| 63.5(b)(4) | Yes | |
| 63.5(b)(5) | Yes | |

| | | |
|---|---|---|
| 63.5(b)(6) | Yes | |
| 63.5(c) | No | Section reserved |
| 63.5(d)(1) | Yes | |
| 63.5(d)(2) | Yes | |
| 63.5(d)(3) | Yes | |
| 63.5(d)(4) | Yes | |
| 63.5(e) | Yes | |
| 63.5(f)(1) | Yes | |
| 63.5(f)(2) | Yes | |
| 63.6(a) | Yes | |
| 63.6(b)(1) | Yes | |
| 63.6(b)(2) | Yes | |
| 63.6(b)(3) | Yes | |
| 63.6(b)(4) | Yes | |
| 63.6(b)(5) | Yes | |
| 63.6(b)(6) | No | Section reserved |
| 63.6(b)(7) | Yes | |
| 63.6(c)(1) | No | Subpart R specifies the compliance date |
| 63.6(c)(2) | Yes | |
| 63.6(c)(3)–(c)(4) | No | Sections reserved |
| 63.6(c)(5) | Yes | |
| 63.6(d) | No | Section reserved |
| 63.6(e) | Yes | |
| 63.6(f)(1) | Yes | |
| 63.6(f)(2) | Yes | |
| 63.6(f)(3) | Yes | |
| 63.6(g) | Yes | |
| 63.6(h) | No | Subpart R does not require COMS |
| 63.6(i)(1)– | Yes | |

| | | |
|---|---|---|
| (i)(14) | | |
| 63.6(i)(15) | No | Section reserved |
| 63.6(i)(16) | Yes | |
| 63.6(j) | Yes | |
| 63.7(a)(1) | Yes | |
| 63.7(a)(2) | Yes | |
| 63.7(a)(3) | Yes | |
| 63.7(b) | Yes | |
| 63.7(c) | Yes | |
| 63.7(d) | Yes | |
| 63.7(e)(1) | Yes | |
| 63.7(e)(2) | Yes | |
| 63.7(e)(3) | Yes | |
| 63.7(e)(4) | Yes | |
| 63.7(f) | Yes | |
| 63.7(g) | Yes | |
| 63.7(h) | Yes | |
| 63.8(a)(1) | Yes | |
| 63.8(a)(2) | Yes | |
| 63.8(a)(3) | No | Section reserved |
| 63.8(a)(4) | Yes | |
| 63.8(b)(1) | Yes | |
| 63.8(b)(2) | Yes | |
| 63.8(b)(3) | Yes | |
| 63.8(c)(1) | Yes | |
| 63.8(c)(2) | Yes | |
| 63.8(c)(3) | Yes | |
| 63.8(c)(4) | Yes | |
| 63.8(c)(5) | No | Subpart R does not require COMS |
| 63.8(c)(6)– | Yes | |

| | | |
|---|---|---|
| (c)(8) | | |
| 63.8(d) | Yes | |
| 63.8(e) | Yes | |
| 63.8(f)(1)–(f)(5) | Yes | |
| 63.8(f)(6) | Yes | |
| 63.8(g) | Yes | |
| 63.9(a) | Yes | |
| 63.9(b)(1) | Yes | |
| 63.9(b)(2) | No | Subpart R allows additional time for existing sources to submit initial notification. Sec. 63.428(a) specifies submittal by 1 year after being subject to the rule or December 16, 1996, whichever is later. |
| 63.9(b)(3) | Yes | |
| 63.9(b)(4) | Yes | |
| 63.9(b)(5) | Yes | |
| 63.9(c) | Yes | |
| 63.9(d) | Yes | |
| 63.9(e) | Yes | |
| 63.9(f) | Yes | |
| 63.9(g) | Yes | |
| 63.9(h)(1)–(h)(3) | Yes | |
| 63.9(h)(4) | No | Section reserved |
| 63.9(h)(5)–(h)(6) | Yes | |
| 63.9(i) | Yes | |
| 63.9(j) | Yes | |
| 63.10(a) | Yes | |
| 63.10(b)(1) | Yes | |
| 63.10(b)(2) | Yes | |
| 63.10(b)(3) | Yes | |

| | | |
|---|---|---|
| 63.10(c)(1) | Yes | |
| 63.10(c)(2)–(c)(4) | No | Sections reserved |
| 63.10(c)(5)–(c)(8) | Yes | |
| 63.10(c)(9) | No | Section reserved |
| 63.10(c)(5)–(c)(8) | Yes | |
| 63.10(d)(1) | Yes | |
| 63.10(d)(2) | Yes | |
| 63.10(d)(3) | Yes | |
| 63.10(d)(4) | Yes | |
| 63.10(d)(5) | Yes | |
| 63.10(e) | Yes | |
| 63.10(f) | Yes | |
| 63.11(a)–(b) | Yes | |
| 63.12(a)–(c) | Yes | |
| 63.13(a)–(c) | Yes | |
| 63.14(a)–(b) | Yes | |
| 63.15(a)–(b) | Yes | |

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment B
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units**

**Source:** 67 FR 17773, Apr. 11, 2002, unless otherwise noted.

**What This Subpart Covers**

**§ 63.1560 What is the purpose of this subpart?**

This subpart establishes national emission standards for hazardous air pollutants (HAP) emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

**§ 63.1561 Am I subject to this subpart?**

(a) You are subject to this subpart if you own or operate a petroleum refinery that is located at a major source of HAP emissions.

(1) A petroleum refinery is an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411, and used mainly for:

(i) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(ii) Separating petroleum; or

(iii) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

(2) A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

(b) [Reserved]

## § 63.1562 What parts of my plant are covered by this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery.

(b) The affected sources are:

(1) The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit ( *i.e.* , the catalyst regeneration flue gas vent).

(2) The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation.

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery.

(4) Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

(c) An affected source is a new affected source if you commence construction of the affected source after September 11, 1998, and you meet the applicability criteria in §63.1561 at the time you commenced construction.

(d) Any affected source is reconstructed if you meet the criteria in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

(f) This subpart does not apply to:

(1) A thermal catalytic cracking unit.

(2) A sulfur recovery unit that does not recover elemental sulfur or where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process).

(3) A redundant sulfur recovery unit not located at a petroleum refinery and used by the refinery only for emergency or maintenance backup.

(4) Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons.

(5) Gaseous streams routed to a fuel gas system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

## § 63.1563 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002.

(2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source.

(b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraph (c) of this section.

(c) We will grant an extension of compliance for an existing catalytic cracking unit allowing additional time to meet the emission limitations and work practice standards for catalytic cracking units in §§63.1564 and 63.1565 if you commit to hydrotreating the catalytic cracking unit feedstock and to meeting the emission limitations of this subpart on the same date that your facility meets the final Tier 2 gasoline sulfur control standard (40 CFR part 80, subpart J). To obtain an extension, you must submit a written notification to your permitting authority according to the requirements in §63.1574(e). Your notification must include the information in paragraphs (c)(1) and (2) of this section.

(1) Identification of the affected source with a brief description of the controls to be installed (if needed) to comply with the emission limitations for catalytic cracking units in this subpart.

(2) A compliance schedule, including the information in paragraphs (c)(2)(i) through (iv) of this section.

(i) The date by which onsite construction or the process change is to be initiated.

(ii) The date by which onsite construction or the process change is to be completed.

(iii) The date by which your facility will achieve final compliance with both the final Tier 2 gasoline sulfur control standard as specified in §80.195, and the emission limitations and work practice standards for catalytic cracking units in this subpart. In no case will your permitting authority grant an extension beyond the date you are required to meet the Tier 2 gasoline sulfur control standard or December 31, 2009, whichever comes first. If you don't comply with the emission limitations and work practice standards for existing catalytic cracking units by the specified date, you will be out-of-compliance with the requirements for catalytic cracking units beginning April 11, 2005.

(iv) A brief description of interim emission control measures that will be taken to ensure proper operation and maintenance of the process equipment during the period of the compliance extension.

(d) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the requirements in paragraphs (d)(1) and (2) of this section apply.

(1) Any portion of the existing facility that is a new affected source or a new reconstructed source must be in compliance with the requirements of this subpart upon startup.

(2) All other parts of the source must be in compliance with the requirements of this subpart by no later than 3 years after it becomes a major source or, if applicable, the extended compliance date granted according to the requirements in paragraph (c) of this section.

(e) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart.

## Catalytic Cracking Units, Catalytic Reforming Units, Sulfur Recovery Units, and Bypass Lines

### § 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for PM, you can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1);

(ii) You can elect to comply with the PM emission limit (Option 2);

(iii) You can elect to comply with the Nickel (Ni) lb/hr emission limit (Option 3); or

(iv) You can elect to comply with the Ni lb/1,000 lbs of coke burn-off emission limit (Option 4).

(2) Comply with each operating limit in Table 2 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 3 of this subpart.

(2) Conduct a performance test for each catalytic cracking unit not subject to the NSPS for PM according to the requirements in §63.1571 and under the conditions specified in Table 4 of this subpart.

(3) Establish each site-specific operating limit in Table 2 of this subpart that applies to you according to the procedures in Table 4 of this subpart.

(4) Use the procedures in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) If you elect Option 1 in paragraph (a)(1)(i) of ths section, the NSPS requirements, compute the PM emission rate (lb/1,000 lbs of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section as follows:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left[ (\%CO/2) + \%CO_2 + \%O_2 \right] + K_3 Q_{ov} \left( \%O_{ov} \right) \qquad (Eq.\ 1)$$

Where:

$R_c$= Coke burn-off rate, kg/hr (lb/hr);

$Q_r$= Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either §63.1573(a)(1) or (a)(2), as applicable, to calculate $Q_r$;

$Q_a$= Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min);

$\%CO_2$= Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$= Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

$K_1$= Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) (0.0186 (lb-min)/(hr-dscf-%));

$K_2$= Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) (0.1303 (lb-min)/(hr-dscf));

$K_3$= Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) (0.0062 (lb-min)/(hr-dscf-%));

$Q_{oxy}$= Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); and

$\%O_{xy}$= Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \qquad (Eq.\ 2)$$

Where:

E = Emission rate of PM, kg/1,000 kg (lb/1,000 lb) of coke burn-off;

$C_s$= Concentration of PM, g/dscm (lb/dscf);

$Q_{sd}$= Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A to part 60 of this chapter, dscm/hr (dscf/hr);

$R_c$= Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 ($kg^2$ /g)/(1,000 kg) (1,000 lb/(1,000 lb)).

$$E_s = 1.0 + A(H/R_c)K' \qquad (Eq.\ 3)$$

Where:

$E_s$= Emission rate of PM allowed, kg/1,000 kg (1b/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions, 0.18 g/million cal (0.10 lb/million Btu); and

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate.

$R_c$= Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K′ = Conversion factor to units to standard, 1.0 ($kg^2$ /g)/(1,000 kg) ($10^3$ lb/(1,000 lb)).

(ii) If you elect Option 2 in paragraph (a)(1)(ii) of this section, the PM emission limit, compute your PM emission rate (lb/1,000 lbs of coke burn-off) using Equations 1 and 2 of this section and your site-specific opacity operating limit (if you use a continuous opacity monitoring system) using Equation 4 of this section as follows:

$$Opacity\ Limit = Opacity_{st} \times \left( \frac{1\,\text{lb/klb coke burn}}{\text{PMEmR}_{st}} \right) \qquad (Eq.\ 4)$$

Where:

Opacity limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$= Hourly average opacity measured during the source test runs, percent; and

$PMEmR_{st}$= PM emission rate measured during the source test, lb/1,000 lbs coke burn.

$$E_{Ni_1} = C_{Ni} \times Q_{sd} \qquad (Eq.\ 5)$$

(iii) If you elect Option 3 in paragraph (a)(1)(iii) of this section, the Ni lb/hr emission limit, compute your Ni emission rate using Equation 5 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 6 and 7 of this section as follows:

Where:

$E_{Ni1}$= Mass emission rate of Ni, mg/hr (lb/hr); and

$C_{Ni}$= Ni concentration in the catalytic cracking unit catalyst regenerator flue gas as measured by Method 29 in appendix A to part 60 of this chapter, mg/dscm (lbs/dscf).

$$Opacity_1 = \frac{13\ \text{g Ni/hr}}{\text{NiEmR1}_{st}} \times Opacity_{st} \qquad (Eq.\ 6)$$

Where:

$Opacity_l$= Opacity value for use in Equation 7 of this section, percent, or 10 percent, whichever is greater; and

$NiEmR1_{st}$= Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each of the performance test runs, g Ni/hr.

$$Ni\ \text{Operating Limit}_1 = Opacity_1 \times Q_{mon,st} \times E\text{-}Cat_{st} \qquad (Eq.\ 7)$$

Where:

Ni operating $limit_1$= Maximum permissible hourly average Ni operating limit, percent-acfm-ppmw, i.e., your site-specific Ni operating limit;

$Q_{mon,st}$= Hourly average actual gas flow rate as measured by the continuous parameter monitoring system during the performance test or using the alternative procedure in §63.1573, acfm; and

$E\text{-}Cat_{st}$= Ni concentration on equilibrium catalyst measured during source test, ppmw.

(iv) If you elect Option 4 in paragraph (a)(1)(iv) of this section, the Ni lbs/1,000 lbs of coke burn-off emission limit, compute your Ni emission rate using Equations 1 and 8 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 9 and 10 of this section as follows:

$$E_{Ni_2} = \frac{C_{Ni} \times Q_{sd}}{R_c} \qquad (Eq.\ 8)$$

Where:

$E_{Ni2}$= Normalized mass emission rate of Ni, mg/kg coke (lb/1,000 lbs coke).

$$Opacity_2 = \frac{1.0\ \text{mg/kg coke}}{\text{NiEmR2}_{st}} \times Opacity_{st} \qquad (Eq.\ 9)$$

Where:

$Opacity_2$= Opacity value for use in Equation 10 of this section, percent, or 10 percent, whichever is greater; and

$NiEmR2_{st}$= Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of this section for each of the performance test runs, mg/kg coke.

$$Ni\ \text{Operating Limit}_2 = Opacity_2 \times E\text{-}Cat_{st} \times \frac{Q_{mon,st}}{R_{c,st}} \qquad (Eq.\ 10)$$

Where:

Ni operating $limit_2$= Maximum permissible hourly average Ni operating limit, percent-ppmw-acfm-hr/kg coke, i.e., your site-specific Ni operating limit; and

$R_{c,st}$= Coke burn rate from Equation 1 of this section, as measured during the initial performance test, kg coke/hr.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan.

(3) If you use a continuous opacity monitoring system and elect to comply with Option 3 in paragraph (a)(1)(iii) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as follows:

$$Ni\ \text{Operating Value}_1 = Opacity \times Q_{mon} \times E\text{-}Cat \qquad (Eq.\ 11)$$

Where:

Ni operating $value_1$= Maximum permissible hourly average Ni standard operating value, %-acfm-ppmw;

Opacity = Hourly average opacity, percent;

$Q_{mon}$= Hourly average actual gas flow rate as measured by continuous parameter monitoring system or calculated by alternative procedure in §63.1573, acfm; and

E-Cat = Ni concentration on equilibrium catalyst from weekly or more recent measurement, ppmw.

(4) If you use a continuous opacity monitoring system and elect to comply with Option 4 in paragraph (a)(1)(iv) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 12 of this section as follows:

$$Ni\ \text{Operating Value}_2 = \frac{Opacity \times E\text{-}Cat \times Q_{mon}}{R_c} \qquad (Eq.\ 12)$$

Where:

Ni operating value$_2$= Maximum permissible hourly average Ni standard operating value, percent-acfm-ppmw-hr/kg coke.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

### § 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit isn't subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1); or

(ii) You can elect to comply with the CO emission limit (Option 2).

(2) Comply with each site-specific operating limit in Table 9 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 10 of this subpart. Except:

(i) Whether or not your catalytic cracking unit is subject to the NSPS for CO in §60.103 of this chapter, you don't have to install and operate a continuous emission monitoring system if you show that CO emissions from your vent average less than 50 parts per million (ppm), dry basis. You must get an exemption from your permitting authority, based on your written request. To show that the emissions average is less than 50 ppm (dry basis), you must continuously monitor CO emissions for 30 days using a CO continuous emission monitoring system that meets the requirements in §63.1572.

(ii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler (including a “CO boiler”) or process heater that has a design heat input capacity of at least 44 megawatts (MW).

(iii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler or process heater in which all vent streams are introduced into the flame zone.

(2) Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in §63.1571 and under the conditions specified in Table 11 of this subpart.

(3) Establish each site-specific operating limit in Table 9 of this subpart that applies to you according to the procedures in Table 11 of this subpart.

(4) Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart.

(5) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status according to §63.1574.

(6) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

## § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare that meets the control device requirements in §63.11(b) (Option 1); or

(ii) You can elect to meet a TOC or nonmethane TOC percent reduction standard or concentration limit, whichever is less stringent (Option 2).

(2) Comply with each site-specific operating limit in Table 16 of this subpart that applies to you.

(3) Except as provided in paragraph (a)(4) of this section, the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents.

(4) The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less.

(5) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 17 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and under the conditions specified in Table 18 of this subpart.

(3) Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart.

(4) Use the procedures in paragraph (b)(4)(i) or (ii) of this section to determine initial compliance with the emission limitations.

(i) If you elect the percent reduction standard under Option 2, calculate the emission rate of nonmethane TOC using Equation 1 of this section (if you use Method 25) or Equation 2 of this section (if you use Method 25A or Methods 25A and 18), then calculate the mass emission reduction using Equation 3 of this section as follows:

$$E = K_4 M_c Q_s \qquad (Eq.\ 1)$$

Where:

E = Emission rate of nonmethane TOC in the vent stream, kilograms-C per hour;

$K_4$= Constant, $6.0 \times 10^{-5}$(kilograms per milligram)(minutes per hour);

$M_c$= Mass concentration of total gaseous nonmethane organic (as carbon) as measured and calculated using Method 25 in appendix A to part 60 of this chapter, mg/dscm; and

$Q_s$= Vent stream flow rate, dscm/min, at a temperature of 20 degrees Celsius (C).

$$E = K_5 \left(C_{TOC} - \tfrac{1}{6} C_{methane}\right) Q_s \qquad (Eq.\ 2)$$

Where:

$K_5$= Constant, $1.8 \times 10^{-4}$ (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (gram-C per gram-mole-hexane) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees C (uses 72g-C/g.mole hexane);

$C_{TOC}$= Concentration of TOC on a dry basis in ppmv as hexane as measured by Method 25A in appendix A to part 60 of this chapter;

$C_{methane}$= Concentration of methane on a dry basis in ppmv as measured by Method 18 in appendix A to part 60 of this chapter. If the concentration of methane is not determined, assume $C_{methane}$equals zero; and

$Q_s$= Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 degrees C.

$$\%\ \text{reduction} = \frac{E_i - E_o}{E_i} \times 100\% \qquad (Eq.\ 3)$$

Where:

$E_i$= Mass emission rate of TOC at control device inlet, kg/hr; and

$E_o$= Mass emission rate of TOC at control device outlet, kg/hr.

(ii) If you elect the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen ($O_2$) content in the gas stream using Equation 4 of this section as follows:

$$C_{NMTOC,3\%O_2} = \left(C_{TOC} - \tfrac{1}{6} C_{methane}\right)\left(\frac{17.9\%}{20.9\% - \%O_2}\right) \qquad (Eq.\ 4)$$

Where:

$C_{NMTOC,\ 3}\%_O2$= Concentration of nonmethane TOC on a dry basis in ppmv as hexane corrected to 3 percent oxygen.

(5) You are not required to do a TOC performance test if:

(i) You elect to vent emissions to a flare as provided in paragraph (a)(1)(i) of this section (Option 1); or

(ii) You elect the TOC percent reduction or concentration limit in paragraph (a)(1)(ii) of this section (Option 2), and you use a boiler or process heater with a design heat input capacity of 44 MW or greater or a boiler or process heater in which all vent streams are introduced into the flame zone.

(6) Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart.

(7) Demonstrate initial compliance with the work practice standard in paragraph (a)(5) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(8) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart.

(2) Demonstrate continuous compliance with the work practice standards in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005]

## § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?

(a) *What emission limitations and work practice standards must I meet?* You must:

(1) Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet a percent reduction standard for hydrogen chloride (HCl) emissions (Option 1); or

(ii) You can elect to meet an HCl concentration limit (Option 2).

(2) Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 24 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and the conditions specified in Table 25 of this subpart.

(3) Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart.

(4) Use the equations in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) Correct the measured HCl concentration for oxygen ($O_2$) content in the gas stream using Equation 1 of this section as follows:

$$C_{HCl,3\%O_2} = \left(\frac{17.9\%}{20.9\% - \%O_2}\right) C_{HCl} \qquad \text{(Eq. 1)}$$

Where:

$C_{HCl,3}\%O_2$= Concentration of HCl on a dry basis in ppmv corrected to 3 percent oxygen or 1 ppmv, whichever is greater;

$C_{HCl}$= Concentration of HCl on a dry basis in ppmv, as measured by Method 26A in 40 CFR part 60, appendix A; and

$\%O_2$= Oxygen concentration in percent by volume (dry basis).

(ii) If you elect the percent reduction standard, calculate the emission rate of HCl using Equation 2 of this section; then calculate the mass emission reduction from the mass emission rates using Equation 3 of this section as follows:

$$E_{HCl} = K_6 C_{HCl} Q_s \qquad \text{(Eq. 2)}$$

Where:

$E_{HCl,}$= Emission rate of HCl in the vent stream, grams per hour;

$K_6$= Constant, 0.091 (parts per million)$^{-1}$(grams HCl per standard cubic meter) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees Celsius (C); and

$Q_s$= Vent stream flow rate, dscm/min, at a temperature of 20 degrees C.

$$HCl\%reduction = \frac{E_{HCl,i} - E_{HCl,o}}{E_{HCl,i}} \times 100\% \qquad \text{(Eq. 3)}$$

Where:

$E_{HCl,i}$= Mass emission rate of HCl at control device inlet, g/hr; and

$E_{HCl,o}$= Mass emission rate of HCl at control device outlet, g/hr.

(iii) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the HCl concentration operating limit, calculate the HCl operating limit using Equation 4 of this section as follows:

$$C_{HCl,ppmvLimit} = 0.9 C_{HCl,AveTube} \left( \frac{C_{HCl,RegLimit}}{C_{HCl,3\%O_2}} \right) \qquad \text{(Eq. 4)}$$

Where:

$C_{HCl,ppmvLimit}$= Maximum permissible HCl concentration for the HCl concentration operating limit, ppmv;

$C_{HCl,AveTube}$= Average HCl concentration from the colormetric tube sampling system, calculated as the arithmetic average of the average HCl concentration measured for each performance test run, ppmv or 1 ppmv, whichever is greater; and

$C_{HCl,RegLimit}$= Maximum permissible outlet HCl concentration for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 10 or 30 ppmv.

(iv) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the percent reduction operating limit, calculate the HCl operating limit using Equation 5 of this section as follows:

$$C_{HCl,\%Limit} = 0.9C_{HCl,AveTube}\left(\frac{100-\%HClReduction_{Limit}}{100-\%HClReduction_{Test}}\right) \qquad \text{(Eq. 5)}$$

Where:

$C_{HCl,\%Limit}$= Maximum permissible HCl concentration for the percent reduction operating limit, ppmv;

%HCl $Reduction_{Limit}$= Minimum permissible HCl reduction for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 97 or 92 percent; and

%HCl $Reduction_{Test}$= Average percent HCl reduction calculated as the arithmetic average HCl reduction calculated using Equation 3 of this section for each performance source test, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standard?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6939, Feb. 9, 2005]

### § 63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) *What emission limitations and work practice standard must I meet?* You must:

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in §60.104 of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit isn't subject to the NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet the NSPS requirements (Option 1); or

(ii) You can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) Meet each operating limit in Table 30 of this subpart that applies to you.

(3) Prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 31 of this subpart.

(2) Conduct each performance test for a sulfur recovery unit not subject to the NSPS for sulfur oxides according to the requirements in §63.1571 and under the conditions specified in Table 32 of this subpart.

(3) Establish each site-specific operating limit in Table 30 of this subpart that applies to you according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as follows:

$$C_{adj} = C_{meas}\left[20.9_c/(20.9 - \%O_2)\right] \qquad (Eq.\ 1)$$

Where:

$C_{adj}$= pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm;

$C_{meas}$= pollutant concentration measured on a dry basis, ppm or g/dscm;

$20.9_c$= 20.9 percent oxygen—0.0 percent oxygen (defined oxygen correction basis), percent;

20.9 = oxygen concentration in air, percent;

$\%O_2$= oxygen concentration measured on a dry basis, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(7) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

### § 63.1569 What are my requirements for HAP emissions from bypass lines?

(a) *What work practice standards must I meet?* (1) You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to install an automated system (Option 1);

(ii) You can elect to use a manual lock system (Option 2);

(iii) You can elect to seal the line (Option 3); or

(iv) You can elect to vent to a control device (Option 4).

(2) As provided in §63.6(g), we, the EPA, may choose to grant you permission to use an alternative to the work practice standard in paragraph (a)(1) of this section.

(3) You must prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan.

(b) *How do I demonstrate initial compliance with the work practice standards?* You must:

(1) If you elect the option in paragraph (a)(1)(i) of this section, conduct each performance test for a bypass line according to the requirements in §63.1571 and under the conditions specified in Table 37 of this subpart.

(2) Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

(4) Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) *How do I demonstrate continuous compliance with the work practice standards?* You must:

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(2) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

## General Compliance Requirements

### § 63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart during the times specified in §63.6(f)(1).

(b) You must be in compliance with the opacity and visible emission limits in this subpart during the times specified in §63.6(h)(1).

(c) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i). During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(d) You must develop a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

(e) [Reserved]

(f) You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.1575.

(g) Consistent with §§63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with §63.6(e)(1). The SSMP must include elements designed to minimize the frequency of such periods (i.e., root cause analysis). The Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

[67 FR 17773, Apr. 11, 2002, as amended at 71 FR 20462, Apr. 20, 2006]

### § 63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test.

(1) For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §63.1563.

(2) For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for your source in §63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in §63.1563.

(3) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, you must demonstrate initial compliance with either the proposed emission limitation or the promulgated emission limitation no later than October 8, 2002 or within 180 calendar days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(4) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, and you chose to comply with the proposed emission limitation when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limitation by October 10, 2005, or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(b) *What are the general requirements for performance test and performance evaluations?* You must:

(1) Conduct each performance test according to the requirements in §63.7(e)(1).

(2) Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(3) Conduct each performance evaluation according to the requirements in §63.8(e).

(4) Not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(5) Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of §63.1564, and determining the arithmetic average of the calculated emission rates.

(c) *What procedures must I use for an engineering assessment?* You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in paragraphs (c)(1) through (c)(4) of this section. Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority.

(1) You may use previous test results provided the tests are representative of current operating practices at the process unit, and provided EPA methods or approved alternatives were used;

(2) You may use bench-scale or pilot-scale test data representative of the process under representative operating conditions;

(3) You may use maximum flow rate, TOC emission rate, organic HAP emission rate, or organic HAP or TOC concentration specified or implied within a permit limit applicable to the process vent; or

(4) You may use design analysis based on engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(i) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(ii) Calculation of hourly average maximum flow rate based on physical equipment design such as pump or blower capacities; and

(iii) Calculation of TOC concentrations based on saturation conditions.

(d) *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of this section.

(1) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iii) in §63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows:

$$Ecat\text{-Limit} = \frac{13 \text{ g Ni/hr}}{NiEmR1_{st}} \times Ecat_{st} \qquad (Eq.\ 1)$$

Where:

Ecat-Limit = Operating limit for equilibrium catalyst Ni concentration, mg/kg;

$NiEmR1_{st}$= Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each performance test run, g Ni/hr; and

$Ecat_{st}$= Average equilibrium Ni concentration from laboratory test results, mg/kg.

(2) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iv) in §63.1564 (Ni lb/1,000 lb of coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows:

$$Ecat\text{-Limit} = \frac{1.0 \text{ mg/kg coke burn-off}}{NiEmR2_{st}} \times Ecat_{st} \qquad (Eq.\ 2)$$

Where:

$NiEmR2_{st}$= Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of §63.1564 for each performance test run, mg/kg coke burn-off.

(3) If you choose to adjust the equilibrium catalyst Ni concentration to the maximum level, you can't adjust any other monitored operating parameter (i.e., gas flow rate, voltage, pressure drop, liquid-to-gas ratio).

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, voltage and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

(e) *Can I change my operating limit?* You may change the established operating limit by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation.

(2) You must establish a revised operating limit for your continuous parameter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in paragraph (e)(1) of this section.

(3) You may change your site-specific opacity operating limit or Ni operating limit only by doing a new performance test.

## § 63.1572 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.

(2) If you use a continuous emission monitoring system to meet the NSPS CO or $SO_2$limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(ii), each continuous emission monitoring system must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) Data must be reduced as specified in §63.8(g)(2).

(b) You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.

(2) If you use a continuous opacity monitoring system to meet the NSPS opacity limit, you must conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in §63.8 and Table 40 of this subpart. This requirement does not apply to an affected source subject to the NSPS that has already demonstrated initial compliance with the applicable performance specification.

(3) As specified in §63.8(c)(4)(i), each continuous opacity monitoring system must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(c) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section.

(1) The owner or operator shall install, operate, and maintain each continuous parameter monitoring system in a manner consistent with the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately. The owner or operator shall also meet the equipment specifications in Table 41 of this subpart if pH strips or colormetric tube sampling systems are used.

(2) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control).

(3) Each continuous parameter monitoring system must have valid hourly average data from at least 75 percent of the hours during which the process operated.

(4) Each continuous parameter monitoring system must determine and record the hourly average of all recorded readings and if applicable, the daily average of all recorded readings for each operating day. The daily average must cover a 24-hour period if operation is continuous or the number of hours of operation per day if operation is not continuous.

(5) Each continuous parameter monitoring system must record the results of each inspection, calibration, and validation check.

(d) You must monitor and collect data according to the requirements in paragraphs (d)(1) and (2) of this section.

(1) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005]

### § 63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. If you use this alternative, you shall use the same procedure for the performance test and for monitoring after the performance test. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator. Or, you may determine and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator using the appropriate control room instrumentation.

(ii) Install and operate a continuous parameter monitoring system to measure and record the temperature of the gases entering the control device (or exiting the catalyst regenerator if you do not use an add-on control device).

(iii) Calculate and record the hourly average actual exhaust gas flow rate using Equation 1 of this section as follows:

$$Q_{gas} = (1.12\,scfm/dscfm) \times (Q_{air} + Q_{other}) \times \left(\frac{Temp_{gas}}{293°K}\right) \times \left(\frac{1atm.}{P_{vent}}\right) \qquad \text{(Eq. 1)}$$

Where

$Q_{gas}$= Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

$Q_{air}$= Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

$Q_{other}$= Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of "other" gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

$Temp_{gas}$= Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

$P_{vent}$= Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the final atmospheric vent stack, you can assume $P_{vent}$= 1 atm.

(2) You may use this alternative to calculating $Q_r$, the volumetric flow rate of exhaust gas for the catalytic cracking regenerator as required in Equation 1 of §63.1564, if you have a gas analyzer installed in the catalytic cracking regenerator exhaust vent prior to the addition of air or other gas streams. You may measure upstream or downstream of an electrostatic precipitator, but you shall measure upstream of a carbon monoxide boiler. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator. Or, you can determine and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator using the catalytic cracking unit control room instrumentation.

(ii) Install and operate a continuous gas analyzer to measure and record the concentration of carbon dioxide, carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust.

(iii) Calculate and record the hourly average flow rate using Equation 2 of this section as follows:

$$Q_r = \frac{79 \times Q_{air} + \left(100 - \%O_{xy}\right) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 2)}$$

Where:

$Q_r$= Volumetric flow rate of exhaust gas from the catalyst regenerator before adding air or gas streams, dscm/min (dscf/min);

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);

$\%O_{xy}$= Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis);

$Q_{oxy}$= Volumetric flow rate of oxygen-enriched air stream to regenerator as determined from the catalytic cracking unit control room instrumentations, dscm/min (dscf/min);

$\%CO_2$= Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis); and

$\%O_2$= Oxygen concentration in regenerator exhaust, percent by volume (dry basis).

(b) *What is the approved alternative for monitoring pH or alkalinity levels?* You may use the alternative in paragraph (b)(1) or (2) of this section for a catalytic reforming unit.

(1) You shall measure and record the pH of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using pH strips as an alternative to a continuous parameter monitoring system. The pH strips must meet the requirements in Table 41 of this subpart.

(2) You shall measure and record the alkalinity of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using titration as an alternative to a continuous parameter monitoring system.

(c) *Can I use another type of monitoring system?* You may request approval from your permitting authority to use an automated data compression system. An automated data compression system does not record monitored operating parameter values at a set frequency (e.g., once every hour) but records all values that meet set criteria for variation from previously recorded values. Your request must contain a description of the monitoring system and data recording system, including the criteria used to determine which monitored values are recorded and retained, the method for calculating daily averages, and a demonstration that the system meets all of the criteria in paragraphs (c)(1) through (5) of this section:

(1) The system measures the operating parameter value at least once every hour;

(2) The system records at least 24 values each day during periods of operation;

(3) The system records the date and time when monitors are turned off or on;

(4) The system recognizes unchanging data that may indicate the monitor is not functioning properly, alerts the operator, and records the incident; and

(5) The system computes daily average values of the monitored operating parameter based on recorded data.

(d) *Can I monitor other process or control device operating parameters?* You may request approval to monitor parameters other than those required in this subpart. You must request approval if:

(1) You use a control device other than a thermal incinerator, boiler, process heater, flare, electrostatic precipitator, or wet scrubber;

(2) You use a combustion control device (e.g., incinerator, flare, boiler or process heater with a design heat capacity of at least 44 MW, boiler or process heater where the vent stream is introduced into the flame zone), electrostatic precipitator, or scrubber but want to monitor a parameter other than those specified; or

(3) You wish to use another type of continuous emission monitoring system that provides direct measurement of a pollutant (i.e., a PM or multi-metals HAP continuous emission monitoring system, a carbonyl sulfide/carbon disulfide continuous emission monitoring system, a TOC continuous emission monitoring system, or HCl continuous emission monitoring system).

(e) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (e)(1) through (5) of this section.

(1) A description of each affected source and the parameter(s) to be monitored to determine whether the affected source will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(2) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine whether the affected source will continuously comply with the emission limitations and the schedule for this demonstration. You must certify that you will establish an operating limit for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(3) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. You also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(4) Supporting calculations.

(5) Averaging time for the alternative operating parameter.

(f) *How do I apply for alternative monitoring requirements if my catalytic cracking unit is equipped with a wet scrubber and I have approved alternative monitoring requirements under the new source performance standards for petroleum refineries?* (1) You may request alternative monitoring requirements according to the procedures in this paragraph if you meet each of the conditions in paragraphs (f)(1)(i) through (iii) of this section:

(i) Your fluid catalytic cracking unit regenerator vent is subject to the PM limit in 40 CFR 60.102(a)(1) and uses a wet scrubber for PM emissions control;

(ii) You have alternative monitoring requirements for the continuous opacity monitoring system requirement in 40 CFR 60.105(a)(1) approved by the Administrator; and

(iii) You are required by this subpart to install, operate, and maintain a continuous opacity monitoring system for the same catalytic cracking unit regenerator vent for which you have approved alternative monitoring requirements.

(2) You can request approval to use an alternative monitoring method prior to submitting your notification of compliance status, in your notification of compliance status, or at any time.

(3) You must submit a copy of the approved alternative monitoring requirements along with a monitoring plan that includes a description of the continuous monitoring system or method, including appropriate operating parameters that will be monitored, test results demonstrating compliance with the opacity limit used to establish an enforceable operating limit(s), and the frequency of measuring and recording to establish continuous compliance. If applicable, you must also include operation and maintenance requirements for the continuous monitoring system.

(4) We will contact you within 30 days of receipt of your application to inform you of approval or of our intent to disapprove your request.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005]

## Notifications, Reports, and Records

### § 63.1574 What notifications must I submit and when?

(a) Except as allowed in paragraphs (a)(1) through (3) of this section, you must submit all of the notifications in §§63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified.

(1) You must submit the notification of your intention to construct or reconstruct according to §63.9(b)(5) unless construction or reconstruction had commenced and initial startup had not occurred before April 11, 2002. In this case, you must submit the notification as soon as practicable before startup but no later than July 10, 2002. This deadline also applies to the application for approval of construction or reconstruction and approval of construction or reconstruction based on State preconstruction review required in §§63.5(d)(1)(i) and 63.5(f)(2).

(2) You must submit the notification of intent to conduct a performance test required in §63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days).

(3) If you are required to conduct a performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to §63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information.

(i) For each initial compliance demonstration that does not include a performance test, you must submit the Notification of Compliance Status no later than 30 calendar days following completion of the initial compliance demonstration.

(ii) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for your affected source in §63.1563.

(b) As specified in §63.9(b)(2), if you startup your new affected source before April 11, 2002, you must submit the initial notification no later than August 9, 2002.

(c) If you startup your new or reconstructed affected source on or after April 11, 2002, you must submit the initial notification no later than 120 days after you become subject to this subpart.

(d) You also must include the information in Table 42 of this subpart in your notification of compliance status.

(e) If you request an extension of compliance for an existing catalytic cracking unit as allowed in §63.1563(c), you must submit a notification to your permitting authority containing the required information by October 13, 2003.

(f) As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each control system and continuous monitoring system for each affected source. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow.

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your part 70 or 71 permit, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan until the change is approved.

(2) Each plan must include, at a minimum, the information specified in paragraphs (f)(2)(i) through (xii) of this section.

(i) Process and control device parameters to be monitored for each affected source, along with established operating limits.

(ii) Procedures for monitoring emissions and process and control device operating parameters for each affected source.

(iii) Procedures that you will use to determine the coke burn-rate, the volumetric flow rate (if you use process data rather than direct measurement), and the rate of combustion of liquid or solid fossil fuels if you use an incinerator-waste heat boiler to burn the exhaust gases from a catalyst regenerator.

(iv) Procedures and analytical methods you will use to determine the equilibrium catalyst Ni concentration, the equilibrium catalyst Ni concentration monthly rolling average, and the hourly or hourly average Ni operating value.

(v) Procedures you will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if you use pH strips.

(vi) Procedures you will use to determine the HCl concentration of gases from a catalytic reforming unit when you use a colormetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment) and the sampling locations that will be used for compliance monitoring purposes.

(vii) Procedures you will use to determine the gas flow rate for a catalytic cracking unit if you use the alternative procedure based on air flow rate and temperature.

(viii) Monitoring schedule, including when you will monitor and when you will not monitor an affected source (e.g., during the coke burn-off, regeneration process).

(ix) Quality control plan for each continuous opacity monitoring system and continuous emission monitoring system you use to meet an emission limit in this subpart. This plan must include procedures you will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

(x) Maintenance schedule for each monitoring system and control device for each affected source that is generally consistent with the manufacturer's instructions for routine and long-term maintenance.

(xi) If you use a fixed-bed gas-solid adsorption system to control emissions from a catalytic reforming unit, you must implement corrective action procedures if the HCl concentration measured at the selected compliance monitoring sampling location within the bed exceeds the operating limit. These procedures must require, at minimum, repeat measurement and recording of the HCl concentration in the adsorption system exhaust gases and at the selected compliance monitoring sampling location within the bed. If the HCl concentration at the selected compliance monitoring location within the bed is above the operating limit during the repeat measurement while the HCl concentration in the adsorption system exhaust gases remains below the operating limit, the adsorption bed must be replaced as soon as practicable. Your procedures must specify the sampling frequency that will be used to monitor the HCl concentration in the adsorption system exhaust gases subsequent to the repeat measurement and prior to replacement of the sorbent material (but not less frequent than once every 4 hours during coke burn-off). If the HCl concentration of the adsorption system exhaust gases is above the operating limit when measured at any time, the adsorption bed must be replaced within 24 hours or before the next regeneration cycle, whichever is longer.

(xii) Procedures that will be used for purging the catalyst if you do not use a control device to comply with the organic HAP emission limits for catalytic reforming units. These procedures will include, but are not limited to, specification of the minimum catalyst temperature and the minimum cumulative volume of gas per mass of catalyst used for purging prior to uncontrolled releases (i.e., during controlled purging events); the

maximum purge gas temperature for uncontrolled purge events; and specification of the monitoring systems that will be used to monitor and record data during each purge event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6941, Feb. 9, 2005]

## § 63.1575 What reports must I submit and when?

(a) You must submit each report in Table 43 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.1563 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.1563.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A) of this chapter, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If there are no deviations from any emission limitation that applies to you and there are no deviations from the requirements for work practice standards, a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system or continuous opacity monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted.

(d) For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (3) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (d)(1) through (3) of this section and the information in paragraphs (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was inoperative, except for zero (low-level) and high-level checks.

(3) The date and time that each continuous opacity monitoring system or continuous emission monitoring system was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging period specified in the regulation for other types of emission limitations), and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period and into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period (recorded in minutes for opacity and hours for gases and in the averaging time specified in the regulation for other types of standards), and the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system as a percent of the total source operating time during that reporting period.

(8) A breakdown of the total duration of downtime for the continuous opacity monitoring system or continuous emission monitoring system during the reporting period into periods that are due to monitoring equipment malfunctions, non-monitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes.

(9) An identification of each HAP that was monitored at the affected source.

(10) A brief description of the process units.

(11) The monitoring equipment manufacturer(s) and model number(s).

(12) The date of the latest certification or audit for the continuous opacity monitoring system or continuous emission monitoring system.

(13) A description of any change in the continuous emission monitoring system or continuous opacity monitoring system, processes, or controls since the last reporting period.

(f) You also must include the information required in paragraphs (f)(1) through (2) of this section in each compliance report, if applicable.

(1) A copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method.

(2) Any requested change in the applicability of an emission standard (e.g., you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your periodic report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

(g) You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information.

(h) The reporting requirements in paragraphs (h)(1) and (2) of this section apply to startups, shutdowns, and malfunctions:

(1) When actions taken to respond are consistent with the plan, you are not required to report these events in the semiannual compliance report and the reporting requirements in §§63.6(e)(3)(iii) and 63.10(d)(5) do not apply.

(2) When actions taken to respond are not consistent with the plan, you must report these events and the response taken in the semiannual compliance report. In this case, the reporting requirements in §§63.6(e)(3)(iv) and 63.10(d)(5) do not apply.

(i) If the applicable permitting authority has approved a period of planned maintenance for your catalytic cracking unit according to the requirements in paragraph (j) of this section, you must include the following information in your compliance report.

(1) In the compliance report due for the 6-month period before the routine planned maintenance is to begin, you must include a full copy of your written request to the applicable permitting authority and written approval received from the applicable permitting authority.

(2) In the compliance report due after the routine planned maintenance is complete, you must include a description of the planned routine maintenance that was performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance.

(j) If you own or operate multiple catalytic cracking units that are served by a single wet scrubber emission control device (e.g., a Venturi scrubber), you may request the applicable permitting authority to approve a period of planned routine maintenance for the control device needed to meet requirements in your operation, maintenance, and monitoring plan. You must present data to the applicable permitting authority demonstrating that the period of planned maintenance results in overall emissions reductions. During this pre-approved time period, the emission control device may be taken out of service while maintenance is performed on the control device and/or one of the process units while the remaining process unit(s) continue to operate. During the period the emission control device is unable to operate, the emission limits, operating limits, and monitoring requirements applicable to the unit that is operating and the wet scrubber emission

control device do not apply. The applicable permitting authority may require that you take specified actions to minimize emissions during the period of planned maintenance.

(1) You must submit a written request to the applicable permitting authority at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.

(2) Your written request must contain the information in paragraphs (j)(2)(i) through (v) of this section.

(i) A description of the planned routine maintenance to be performed during the next 6 months and why it is necessary.

(ii) The date the planned maintenance will begin and end.

(iii) A quantified estimate of the HAP and criteria pollutant emissions that will be emitted during the period of planned maintenance.

(iv) An analysis showing the emissions reductions resulting from the planned maintenance as opposed to delaying the maintenance until the next unit turnaround.

(v) Actions you will take to minimize emissions during the period of planned maintenance.

### § 63.1576 What records must I keep, in what form, and for how long?

(a) You must keep the records specified in paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, performance evaluations, and opacity and visible emission observations as required in §63.10(b)(2)(viii).

(b) For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring systems during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superceded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records in §63.6(h) for visible emission observations.

(d) You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you.

(e) You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan.

(f) You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater.

(g) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(h) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(i) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

## Other Requirements and Information

### § 63.1577 What parts of the General Provisions apply to me?

Table 44 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

### § 63.1578 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limitations and work practice standards in §§63.1564 through 63.1569 under §63.6(g).

(2) Approval of alternative opacity emission limitations in §§63.1564 through 63.1569 under §63.6(h)(9).

(3) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

## § 63.1579 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, the General Provisions of this part (§§63.1 through 63.15), and in this section as listed.

*Boiler* means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

*Catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and equipment used for heat recovery.

*Catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs and includes the regenerator combustion air blower(s).

*Catalytic reforming unit* means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis. The catalytic reforming unit includes the reactor, regenerator (if separate), separators, catalyst isolation and transport vessels (e.g., lock and lift hoppers), recirculation equipment, scrubbers, and other ancillary equipment.

*Catalytic reforming unit regenerator* means one or more regenerators which comprise that portion of the catalytic reforming unit and ancillary equipment in which the following regeneration steps typically are performed: depressurization, purge, coke burn-off, catalyst rejuvenation with a chloride (or other halogenated) compound(s), and a final purge. The catalytic reforming unit catalyst regeneration process can be done either as a semi-regenerative, cyclic, or continuous regeneration process.

*Coke burn-off* means the coke removed from the surface of the catalytic cracking unit catalyst or the catalytic reforming unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated using Equation 2 in §63.1564.

*Combustion device* means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the destruction of organic HAP or VOC.

*Combustion zone* means the space in an enclosed combustion device (e.g., vapor incinerator, boiler, furnace, or process heater) occupied by the organic HAP and any supplemental fuel while burning. The combustion zone includes any flame that is visible or luminous as well as that space outside the flame envelope in which the organic HAP continues to be oxidized to form the combustion products.

*Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminants from petroleum derivatives.

*Continuous regeneration reforming* means a catalytic reforming process characterized by continuous flow of catalyst material through a reactor where it mixes with feedstock, and a portion of the catalyst is continuously removed and sent to a special regenerator where it is regenerated and continuously recycled back to the reactor.

*Control device* means any equipment used for recovering, removing, or oxidizing HAP in either gaseous or solid form. Such equipment includes, but is not limited to, condensers, scrubbers, electrostatic precipitators, incinerators, flares, boilers, and process heaters.

*Cyclic regeneration reforming* means a catalytic reforming process characterized by continual batch regeneration of catalyst in situ in any one of several reactors (e.g., 4 or 5 separate reactors) that can be isolated from and returned to the reforming operation while maintaining continuous reforming process operations (i.e., feedstock continues flowing through the remaining reactors without change in feed rate or product octane).

*Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

*Emission limitation* means any emission limit, opacity limit, operating limit, or visible emission limit.

*Flame zone* means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

*Flow indicator* means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in or through a line.

*Fuel gas system* means the offsite and onsite piping and control system that gathers gaseous streams generated by the source, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

*HCl* means for the purposes of this subpart, gaseous emissions of hydrogen chloride that serve as a surrogate measure for total emissions of hydrogen chloride and chlorine as measured by Method 26 or 26A in appendix A to part 60 of this chapter or an approved alternative method.

*Incinerator* means an enclosed combustion device that is used for destroying organic compounds, with or without heat recovery. Auxiliary fuel may be used to heat waste gas to combustion temperatures. An incinerator may use a catalytic combustion process where a substance is introduced into an exhaust stream to burn or oxidize contaminants while the substances itself remains intact, or a thermal process which uses elevated temperatures as a primary means to burn or oxidize contaminants.

*Internal scrubbing system* means a wet scrubbing, wet injection, or caustic injection control device that treats (in-situ) the catalytic reforming unit recirculating coke burn exhaust gases for acid (HCl) control during reforming catalyst regeneration upstream of the atmospheric coke burn vent.

*Ni* means, for the purposes of this subpart, particulate emissions of nickel that serve as a surrogate measure for total emissions of metal HAP, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Method 29 in appendix A to part 60 of this chapter or by an approved alternative method.

*Nonmethane TOC* means, for the purposes of this subpart, emissions of total organic compounds, excluding methane, that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25 in appendix A to part 60 of this chapter, by the combination of Methods 18 and 25A in appendix A to part 60 of this chapter, or by an approved alternative method.

*Oxidation control system* means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to sulfur dioxide.

*PM* means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Methods 5B or 5F in appendix A to part 60 of this chapter or by an approved alternative method.

*Process heater* means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

*Process vent* means, for the purposes of this subpart, a gas stream that is continuously or periodically discharged during normal operation of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit, including gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device line prior to control or discharge to the atmosphere.

*Reduced sulfur compounds* means hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

*Reduction control system* means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to hydrogen sulfide.

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Semi-regenerative reforming* means a catalytic reforming process characterized by shutdown of the entire reforming unit (e.g., which may employ three to four separate reactors) at specified intervals or at the owner's or operator's convenience for in situ catalyst regeneration.

*Sulfur recovery unit* means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide. This definition does not include a unit where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur, e.g., the LO-CAT II process.

*TOC* means, for the purposes of this subpart, emissions of total organic compounds that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25A in appendix A to part 60 of this chapter or by an approved alternative method.

*TRS* means, for the purposes of this subpart, emissions of total reduced sulfur compounds, expressed as an equivalent sulfur dioxide concentration, that serve as a surrogate measure of the total emissions of sulfide HAP carbonyl sulfide and carbon disulfide as measured by Method 15 in appendix A to part 60 of this chapter or by an approved alternative method.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 1 to Subpart UUU of Part 63—Metal HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | You shall meet the following emission limits for each catalyst regenerator vent . . . |
|---|---|
| 1. Subject to new source performance standard (NSPS) for PM in 40 CFR 60.102 | PM emissions must not the exceed 1.0 kilogram (kg) per 1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or in supplemental liquid or solid fossil fuel, the incremental rate of PM emissions must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. |
| 2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102 | PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. |
| 3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102 | PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. |
| 4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102 | Nickel (Ni) emissions must not exceed 13,000 milligrams per hour (mg/hr) (0.029 lb/hr). |
| 5. Option 4: Ni Lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102 | Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 2 to Subpart UUU of Part 63—Operating Limits for Metal HAP Emissions From Catalytic Cracking Units**

As stated in §63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | For this type of continuous monitoring system . . . | For this type of control device . . . | You shall meet this operating limit . . . |
|---|---|---|---|
| 1. Subject to the NSPS for PM in 40 CFR 60.102. | Continuous opacity monitoring system. | Not applicable | Not applicable. |
| 2. Option 1: NSPS requirements not subject to the NSPS for PM in 40 CFR 60.102. | Continuous opacity monitoring system. | Not applicable | Not applicable. |
| 3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102. | a. Continuous opacity monitoring system. | Electrostatic precipitator | Maintain the hourly average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test. |
| | b. Continuous parameter monitoring systems. | Electrostatic precipitator | Maintain the daily average gas flow rate no higher than the limit established in the performance test; and maintain the daily average voltage and secondary current (or total power input) above the limit established in the performance test. |
| | c. Continuous parameter monitoring systems. | Wet scrubber | Maintain the daily average pressure drop above the limit established in the performance test (not applicable to a wet scrubber of the non-venturi jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established in the performance test. |
| 4. Option 3: Ni lb/hr not subject to the NSPS for PM | a. Continuous opacity monitoring | Electrostatic precipitator | Maintain the daily average Ni operating value no higher than the limit established during the |

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| in 40 CFR 60.102. | system. | | performance test. |
| | b. Continuous parameter monitoring systems. | i. Electrostatic precipitator | Maintain the daily average gas flow rate no higher than the limit established during the performance test; maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; and maintain the daily average voltage and secondary current (or total power input) above the established during the performance test. |
| | | ii. Wet scrubber | Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established during the performance test. |
| 5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102 | a. Continuous opacity monitoring system | Electrostatic precipitator | Maintain the daily average Ni operating value no higher than the Ni operating limit established during the performance test. |
| | b. Continuous parameter monitoring systems. | i. Electrostatic precipitator | Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; and maintain the daily average voltage and secondary current for total power input) above the limit established during the performance test. |

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| | | ii. Wet scrubber | Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test; maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design); and maintain the daily average liquid-to-gas ratio above the limit established during the performance test. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 3 to Subpart UUU of Part 63—Continous Monitoring Systems for Metal HAP Emissions From Catalytic Cracking Units**

As stated in §63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | If your catalytic cracking unit is . . . | And you use this type of control device for your vent . . . | You shall install, operate, and maintain a . . . |
|---|---|---|---|
| 1. Subject to the NSPS for PM in 40 CFR 60.102 | Any size | Electrostatic precipitator or wet scrubber or no control device | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. |
| 2. Option 1: NSPS limits not subject to the NSPS for PM in 40 CFR 60.102 | Any size | Electrostatic precipitator or wet scrubber or no control device | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. |
| 3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102 | a. Over 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. |

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| | b. Up to 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device[1]and the voltage and secondary current (or total power input) to the control device. |
| | c. Any size | i. Wet scrubber | (1) Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, gas flow rate entering or exiting the control device[1], and total liquid (or scrubbing liquor) flow rate to the control device. |
| | | | (2) If you use a wet scrubber of the non-venturi jet-ejector design, you're not required to install and operate a continuous parameter monitoring system for pressure drop. |
| | d. Any size | No electrostatic precipitator or wet scrubber | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regnerator vent. |
| 4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102 | a. Over 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]. |
| | b. Up to 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device[1]and the voltage and secondary |

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| | | | current (or total power input) to the control device. |
| | c. Any size | Wet scrubber | (1) Continuous parameter monitoring system to measure and record the pressure drop across the scrubber, gas flow rate entering or exiting the control device[1], and total liquid (or scrubbing liquor) flow rate to the control device. |
| | | | (2) If you use a wet scrubber of the non-venturi jet-ejector design, you're not required to install and operate a continuous parameter monitoring system for pressure drop. |
| | d. Any size | No electrostatic precipitator or wet scrubber | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate[1]. |
| 5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102 | a. Over 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]. |
| | b. Up to 20,000 barrels per day fresh feed capacity | Electrostatic precipitator | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]; or continuous parameter monitoring systems to measure and record the gas flow rate entering or exiting the control device[1]and the voltage and secondary current (or total power input) to the control device. |
| | c. Any size | Wet scrubber | Continuous parameter monitoring system to measure and record the |

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| | | | pressure drop across the scrubber, gas flow rate entering or exiting the control device[1], and total liquid (or scrubbing liquor) flow rate to the control device. |
| | d. Any size | No electrostatic precipitator or wet scrubber | Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate[1]. |

[1]If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate.

[70 FR 6942, Feb. 9, 2005]

**Table 4 to Subpart UUU of Part 63—Requirements for Performance Tests for Metal HAP Emissions From Catalytic Cracking Units Not Subject to the New Source Performance Standard (NSPS) for Particulate Matter (PM)**

As stated in §63.1564(b)(2), you shall meet each requirement in the following table that applies to you.

| For each new or existing catalytic cracking unit catalyst regenerator vent . . . | You must . . . | Using . . . | According to these requirements . . . |
|---|---|---|---|
| 1. If you elect Option 1 in item 2 of Table 1, Option 2 in item 3 of Table 1, Option 3 in item 4 of Table 1, or Option 4 in item 5 of Table 1 of this subpart. | a. Select sampling port's location and the number of traverse ports. | Method 1 or 1A in appendix A to part 60 of this chapter. | Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere. |
| | b. Determine velocity and volumetric flow rate. | Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable. | |
| | c. Conduct gas | Method 3, 3A, or 3B in | |

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| | molecular weight analysis. | appendix A to part 60 of this chapter, as applicable. | |
| | d. Measure moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. | |
| | e. If you use an electro-static precipitator, record the total number of fields in the control system and how many operated during the applicable performance test. | | |
| | f. If you use a wet scrubber, record the total amount (rate) of water (or scrubbing liquid) and the amount (rate) of make-up liquid to the scrubber during each test run. | | |
| 2. Option 1: Elect NSPS | a. Measure PM emissions. | Method 5B or 5F (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5B (40 CFR part 60, appendix A) to determine PM emissions and associated moisture content for unit with wet scrubber. | You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min). |
| | b. Compute PM | Equations 1, 2, and 3 | |

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| | emission rate (lbs/1,000 lbs) of coke burn-off. | of §63.1564 (if applicable). | |
| | c. Measure opacity of emissions. | Continuous opacity monitoring system. | You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5B or 5F performance test and reduce the data to 6-minute averages. |
| 3. Option 2: PM limit | a. Measure PM emissions. | See item 2. of this table. | See item 2. of this table. |
| | b. Compute coke burn-off rate and PM emission rate. | Equations 1 and 2 of §63.1564. | |
| | c. Establish your site-specific opacity operating limit if you use a continuous opacity monitoring system. | Data from the continuous opacity monitoring system. | You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5B or 5F performance test and reduce the data to 6-minute averages; determine and record the hourly average opacity from all the 6-minute averages; and compute the site-specific limit using Equation 4 of §63.1564. |
| 4. Option 3: Ni lb/hr | a. Measure concentration of Ni and total metal HAP. | Method 29 (40 CFR part 60, appendix A). | |
| | b. Compute Ni emission rate (lb/hr). | Equation 5 of §63.1564. | |
| | c. Determine the equilibrium catalyst Ni concentration. | XRF procedure in appendix A to this subpart[1]; or EPA Method 6010B or 6020 | You must obtain 1 sample for each of the 3 runs; determine and record the equilibrium catalyst Ni |

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| | | or EPA Method 7520 or 7521 in SW–846[2]; or an alternative to the SW-846 method satisfactory to the Administrator. | concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571. |
| | d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit. | i. Equations 6 and 7 of §63.1564 using data from continuous opacity monitoring system, gas flow rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test. | (1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the hourly average opacity from all the 6-minute averages. |
| | | | (2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate from all the readings. |
| 5. Option 4: Ni lbs/1,000 lbs of coke burn-off | a. Measure concentration of Ni and total HAP. | Method 29 (40 CFR part 60, appendix A). | |
| | b. Compute Ni emission rate (lb/1,000 lbs of coke burn-off). | Equations 1 and 8 of §63.1564. | |
| | c. Determine the equilibrium catalyst Ni concentration. | See item 4.c. of this table. | You must obtain 1 sample for each of the 3 runs; determine and record the equilibrium catalyst Ni |

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| | | | concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571. |
| | d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit. | i. Equations 9 and 10 of §63.1564 with data from continuous opacity monitoring system, coke burn-off rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test. | (1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the hourly average opacity from all the 6-minute averages. |
| | | | (2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow rate as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate from all the readings. |
| | e. Record the catalyst addition rate for each test and schedule for the 10- day period prior to the test. | | |
| 6. If you elect Option 2 in Entry 3 in Table 1, Option 3 in Entry 4 in Table 1, or Option 4 in Entry | a. Establish each operating limit in Table 2 of this subpart that applies to you. | Data from the continuous parameter monitoring systems and applicable performance test methods. | |

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| 5 in Table 1 of this subpart and you use continuous parameter monitoring systems. | | | |
| | b. Electrostatic precipitator or wet scrubber: gas flow rate. | Data from the continuous parameter monitoring systems and applicable performance test methods. | You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the maximum hourly average gas flow rate from all the readings. |
| | c. Electrostatic precipitator: voltage and secondary current (or total power input). | Data from the continuous parameter monitoring systems and applicable performance test methods. | You must collect voltage and secondary current (or total power input) monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the minimum hourly average voltage and secondary current (or total power input) from all the readings. |
| | d. Electrostatic precipitator or wet scrubber: equilibrium catalyst Ni concentration. | Results of analysis for equilibrium catalyst Ni concentration. | You must determine and record the average equilibrium catalyst Ni concentration for the 3 runs based on the laboratory results. You may adjust the value using Equation 1 or 2 of §63.1571 as applicable. |
| | e. Wet scrubber: pressure drop (not applicable to non-venturi scrubber of | Data from the continuous parameter monitoring systems and applicable | You must collect pressure drop monitoring data every 15 minutes during the entire period of the |

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| | jet ejector design). | performance test methods. | initial performance test; and determine and record the minimum hourly average pressure drop from all the readings. |
| | f. Wet scrubber: liquid-to-gas ratio | Data from the continuous parameter monitoring systems and applicable performance test methods. | You must collect gas flow rate and total water (or scrubbing liquid) flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate from all the readings; and determine and record the minimum liquid-to-gas ratio. |
| | g. Alternative procedure for gas flow rate. | Data from the continuous parameter monitoring systems and applicable performance test methods. | You must collect air flow rate monitoring data or determine the air flow rate using control room instrumentation every 15 minutes during the entire period of the initial performance test; determine and record the hourly average rate of all the readings; and determine and record the maximum gas flow rate using Equation 1 of §63.1573. |

[1]Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure).

[2]EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, and EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield,

VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6944, Feb. 9, 2005]

**Table 5 to Subpart UUU of Part 63—Initial Compliance With Metal HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic cracking unit catalyst regenerator vent . . . | For the following emission limit . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| 1. Subject to the NSPS for PM in 40 CFR 60.102 | PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period | You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. If applicable, you have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM rate is less than or equal to 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel. As part of the Notification of Compliance Status, you must certify that your vent meets the PM emission limit. You are not required to do another performance test to demonstrate initial compliance. You have |

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| | | already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent. Except: One 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the opacity limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in §63.1572. You are not required to do a performance evaluation to demonstrate initial compliance. |
| 2. Option 1: Elect NSPS not subject to the NSPS for PM | PM emission must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period | The average PM emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or 5B (for a unit with a wet scrubber), over the period of the initial performance test, is no higher than 1.0 kg/1,000 kg (1.0 lb/1,000 lb of coke burn-off in the catalyst regenerator. The PM emission rate is calculated using Equations 1 and 2 of §63.1564. If applicable, the average PM emission rate, measured using EPA Method 5B emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or Method 5B (for a unit with a wet scrubber) over the period of the initial performance test, is no higher than 43.0 g/GJ (0.10 lb/million Btu) of heat input |

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| | | attributable to the liquid or solid fossil fuel. The PM emission rate is calculated using Equation 3 of §63.1564; no more than one 6-minute average measured by the continuous opacity monitoring system exceeds 30 percent opacity in any 1-hour period over the period of the performance test; and your performance evaluation shows the continuous opacity monitoring system meets the applicable requirements in §63.1572. |
| 3. Option 2: Not subject to the NSPS for PM | PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator | The average PM emission rate, measured using EPA Method 5B or 5F (for a unit without a wet scrubber) or Method 5B (for a unit with a wet scrubber), over the period of the initial performance test, is less than or equal to 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The PM emission rate is calculated using Equations 1 and 2 of §63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572. |
| 4. Option 3: not subject to the NSPS for PM | Nickel (Ni) emissions from your catalyst regenerator vent must not exceed 13,000 mg/hr (0.029 lb/hr). | The average Ni emission rate, measured using Method 29 over the period of the initial performance test, is not more than 13,000 mg/hr (0.029 lb/hr). The Ni emission rate is calculated using Equation 5 of §63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572. |
| 5. Option 4: Ni | Ni emissions from your catalyst | The average Ni emission rate, |

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| lb/1,000 lbs of coke burn-off not subject to the NSPS for PM. | regenerator vent must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. | measured using Method 29 over the period of the initial performance test, is not more than 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. The Ni emission rate is calculated using Equation 8 of §63.1564; and if you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6946, Feb. 9, 2005]

**Table 6 to Subpart UUU of Part 63—Continuous Compliance With Metal HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic cracking unit . . . | Subject to this emission limit for your catalyst regenerator vent . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|
| 1. Subject to the NSPS for PM in 40 CFR 60.102 | a. PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period | i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 kg/1,000 kg (1.0 lb/1,000 lbs) of coke burn-off; if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler; if applicable, maintaining the PM rate incinerator below 43 g/GJ (0.10 lb/million Btu) of heat input |

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| | | attributable to the solid or liquid fossil fuel; collecting the continuous opacity monitoring data for each catalyst regenerator vent according to §63.1572; and maintaining each 6-minute average at or below 30 percent except that one 6-minute average during a 1-hour period can exceed 30 percent. |
| 2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102 | See item 1.a. of this table | See item 1.a.i. of this table. |
| 3. Option 2: PM limit not subject to the NSPS for PM | PM emissions must not exceed 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator | Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data to determine the volumetric flow rate); and maintaining the PM emission rate below 1.0 kg/1,000 kg (1.0 lb/1,000 lb) of coke burn-off. |
| 4. Option 3: Ni lb/hr not subject to the NSPS for PM. | Ni emissions must not exceed 13,000 mg/hr (0.029 lb/hr). | Maintaining Ni emission rate below 13,000 mg/hr (0.029 lb/hr). |
| 5. Option 4: Ni lb/1,000 lbs of coke burn-off not subject to the NSPS for PM | Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator | Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data to determine the volumetric flow rate); and maintaining Ni emission rate below 1.0 mg/kg (0.001 lb/1,000 lbs) of coke burn-off in the catalyst regenerator. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 7 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Metal HAP Emissions From Catalytic Cracking Units**

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | If you use . . . | For this operating limit . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|---|
| 1. Subject to NSPS for PM in 40 CFR 60.102. | Continuous opacity monitoring system. | Not applicable. | Complying with Table 6 of this subpart. |
| 2. Option 1: Elect NSPS not subject to the NSPS for PM in 40 CFR 60.102. | Continuous opacity monitoring system. | Not applicable. | Complying with Table 6 of this subpart. |
| 3. Option 2: PM limit not subject to the NSPS for PM in 40 CFR 60.102. | a. Continuous opacity monitoring system. | The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test. | Collecting the hourly average continuous opacity monitoring system data according to §63.1572; and maintaining the hourly average opacity at or below the site-specific limit. |
| | b. Continuous parameter monitoring systems—electrostatic precipitator. | i. The daily average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test. | Collecting the hourly and daily average gas flow rate monitoring data according to §63.1572[1]; and maintaining the daily average gas flow rate at or below the limit established during the performance test. |
| | | ii. The daily average voltage and secondary current (or total power input) to the control device must not fall below the operating | Collecting the hourly and daily average voltage and secondary current (or total power input) monitoring data according to §63.1572; and maintaining the daily average voltage and |

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| | | limit established during the performance test. | secondary current (or total power input) at or above the limit established during the performance test. |
| | c. Continuous parameter monitoring systems—wet scrubber. | i. The daily average pressure drop across the scrubber must not fall below the operating limit established during the performance test. | Collecting the hourly and daily average pressure drop monitoring data according to §63.1572; and maintaining the daily average pressure drop above the limit established during the performance test. |
| | | ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test. | Collecting the hourly average gas flow rate and water (or scrubbing liquid) flow rate monitoring data according to §63.1572[1]; determining and recording the hourly average liquid-to-gas ratio; determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test. |
| 4. Option 3: Ni lb/hr not subject to the NSPS for PM in 40 CFR 60.102. | a. Continuous opacity monitoring system. | The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test. | Collecting the hourly average continuous opacity monitoring system data according to §63.1572; determining and recording equilibrium catalyst Ni concentration at least once a week[2]; collecting the hourly average gas flow rate monitoring data according to §63.1572[1]; determining and recording the hourly average Ni operating value using Equation 11 of §63.1564; determining and recording the daily average Ni operating value; and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test. |

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| | b. Continuous parameter monitoring systems—electrostatic precipitator. | i. The daily average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test. | See item 3.b.i. of this table. |
| | | ii. The daily average voltage and secondary current (or total power input) must not fall below the level established in the performance test. | See item 3.b.ii. of this table. |
| | | iii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test. | Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test. |
| | c. Continuous parameter monitoring systems—wetscrubber. | i. The daily average pressure drop must not fall below the operating limit established in the performance test. | See item 3.c.i. of this table. |
| | | ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test. | See item 3.c.ii. of this table. |
| | | iii. The monthly rolling average equilibrium catalyst Ni concentration must not | Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and |

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| | | exceed the level established during the performance test. | recording the monthly rolling average of equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test. |
| 5. Option 4: Ni lb/ton of coke burn-off not subject to the NSPS for PM in 40 CFR 60.102. | a. Continuous opacity monitoring system. | The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test. | Collecting the hourly average continuous opacity monitoring system data according to §63.1572; collecting the hourly average gas flow rate monitoring data according to §63.1572[1]; determining and recording equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the hourly average Ni operating value using Equation 12 of §63.1564; determining and recording the daily average Ni operating value; and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test. |
| | b. Continuous parameter monitoring systems—electrostatic precipitator. | i. The daily average gas flow rate to the control device must not exceed the level established in the performance test. | See item 3.b.i. of this table. |
| | | ii. The daily average voltage and secondary current (or total power input) must not fall below the level established in the performance test. | See item 3.b.ii. of this table. |
| | | iii. The monthly rolling average equilibrium | See item 4.b.iii. of this table. |

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| | | catalyst Ni concentration must not exceed the level established during the performance test. | |
| | c. Continuous parameter monitoring systems—wet scrubber. | i. The daily average pressure drop must not fall below the operating limit established in the performance test. | See item 3.c.i. of this table. |
| | | ii. The daily average liquid-to-gas ratio must not fall below the operating limit established during the performance test. | See item 3.c.ii. of this table. |
| | | iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test. | See item 4.c.iii. of this table. |

[1]If applicable, you can use the alternative in §63.1573(a)(1) for gas flow rate instead of a continuous parameter monitoring system if you used the alternative method in the initial performance test.

[2]The equilibrium catalyst Ni concentration must be measured by the procedure, Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to this subpart; or by EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, or EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration; or by an alternative to EPA Method 6010B, 6020, 7520, or 7521 satisfactory to the Administrator. The EPA Methods 6010B, 6020, 7520, and 7521 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm.*

[70 FR 6948, Feb. 9, 2005]

**Table 8 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

| For each new and existing catalytic cracking unit . . . | You shall meet the following emission limit for each catalyst regenerator vent . . . |
|---|---|
| 1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 | CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis). |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).<br>b. If you use a flare to meet the CO limit, the flare must meet the requirements for control devices in §63.11(b): visible emissions must not exceed a total of 5 minutes during any 2 consecutive hours. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 9 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Cracking Units**

As stated in §63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | For this type of continuous monitoring system . . . | For this type of control device . . . | You shall meet this operating limit . . . |
|---|---|---|---|
| 1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 | Continuous emission monitoring system. | Not applicable | Not applicable. |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | a. Continuous emission monitoring system. | Not applicable | Not applicable. |
| | b. Continuous parameter monitoring | i. Thermal incinerator | Maintain the daily average combustion zone temperature above the limit established during |

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| | systems. | | the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test. |
| | | ii. Boiler or process heater with a design heat input capacity under 44 MW or a boiler or process heater in which all vent streams are not introduced into the flame zone. | Maintain the daily average combustion zone temperature above the limit established in the performance test. |
| | | iii. Flare | The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 10 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Cracking Units**

As stated in §63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

| For each new or existing catalytic cracking unit . . . | And you use this type of control device for your vent . . . | You shall install, operate, and maintain this type of continuous monitoring system . . . |
|---|---|---|
| 1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103. | Not applicable | Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent. |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | a. Thermal incinerator | Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous |

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| | | parameter monitoring systems to measure and record the combustion zone temperature and oxygen content (percent, dry basis) in the incinerator vent stream. |
| | b. Process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone. | Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature. |
| | c. Flare | Monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame. |
| | d. No control device | Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)**

As stated in §63.1565(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

| For . . . | You must . . . | Using . . . | According to these requirements . . . |
|---|---|---|---|
| 1. Each new or existing catalytic cracking unit catalyst regenerator vent. | a. Select sampling port's location and the number of traverse ports. | Method 1 or 1A in appendix A to part 60 of this chapter. | Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere. |
| | b. Determine velocity and volumetric flow rate. | Method 2, 2A, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as | |

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| | | applicable. | |
| | c. Conduct gas molecular weight analysis. | Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable. | |
| | d. Measure moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. | |
| 2. For each new or existing catalytic cracking unit catalyst regenerator vent if you use a continuous emission monitoring system. | Measure CO emissions | Data from your continuous emission monitoring system. | Collect CO monitoring data for each vent for 24 consecutive operating hours; and reduce the continuous emission monitoring data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period. |
| 3. Each catalytic cracking unit catalyst regenerator vent if you use continuous parameter monitoring systems. | a. Measure the CO concentration (dry basis) of emissions exiting the control device. | Method 10, 10A, or 10B in appendix A to part 60 of this chapter, as applicable. | |
| | b. Establish each operating limit in Table 9 of this subpart that applies to you. | Data from the continuous parameter monitoring systems. | |
| | c. Thermal incinerator combustion zone temperature. | Data from the continuous parameter monitoring systems. | Collect temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average |

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| | | | combustion zone temperature from all the readings. |
| | d. Thermal incinerator: oxygen, content (percent, dry basis) in the incinerator vent stream. | Data from the continuous parameter monitoring systems. | Collect oxygen concentration (percent, dry basis) monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average percent excess oxygen concentration from all the readings. |
| | e. If you use a process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone, establish operating limit for combustion zone temperature. | Data from the continuous parameter monitoring systems. | Collect the temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings. |
| | f. If you use a flare, conduct visible emission observations. | Method 22 (40 CFR part 60, appendix A). | Maintain a 2-hour observation period; and record the presence of a flame at the pilot light over the full period of the test. |
| | g. If you use a flare, determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity. | 40 CFR 60.11(b)(6)through(8). | |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic cracking unit . . . | For the following emission limit . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| 1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 | CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). | You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance. |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). | i. If you use a continuous parameter monitoring system, the average CO emissions measured by Method 10 over the period of the initial performance test are less than or equal to 500 ppmv (dry basis). |
| | | ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in §63.1572. |

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|---|---|---|
| | b. If you use a flare, visible emissions must not exceed a total of 5 minutes during any 2 operating hours. | Visible emissions, measured by Method 22 during the 2-hour observation period during the initial performance test, are no higher than 5 minutes. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 13 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Cracking Units**

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic cracking unit . . . | Subject to this emission limit for your catalyst regenerator vent . . . | If you must . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|---|
| 1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 | CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). | Continuous emission monitoring system | Collecting the hourly average CO monitoring data according to §63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis). |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | i. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). | Continuous emission monitoring system. | Same as above. |
| | ii. CO emissisons from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). | Continuous parameter monitoring system. | Maintaining the hourly average CO concentration below 500 ppmv (dry basis). |
| | iii. Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour period. | Control device-flare | Maintaining visible emissions below a total of 5 minutes during any 2-hour operating period. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 14 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Cracking Units**

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

| For each new existing catalytic cracking unit . . . | If you use . . . | For this operating limit . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|---|
| 1. Subject to NSPS for carbon monoxide (CO) in 40 CFR 60.103 | Continuous emission monitoring system. | Not applicable | Complying with Table 13 of this subpart. |
| 2. Not subject to the NSPS for CO in 40 CFR 60.103 | a. Continuous emission monitoring system | Not applicable | Complying with Table 13 of this subpart. |
| | b. Continuous parameter monitoring systems—thermal incinerator. | i. The daily average combustion zone temperature must not fall below the level established during the performance test. | Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test. |
| | | ii. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test. | Collecting the hourly and daily average oxygen concentration monitoring data according to §63.1572; and maintaining the daily average oxygen concentration above the limit established during the performance test. |
| | c. Continuous parameter monitoring systems—boiler or process heater | The daily combustion zone temperature must not fall below | Collecting the average hourly and daily temperature monitoring |

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| | with a design heat input capacity under 44 MW or boiler or process heater in which all vent streams are not introduced into the flame zone. | the level established in the performance test. | data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test. |
| | d. Continuous parameter monitoring system—flare. | The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it. | Collecting the flare monitoring data according to §63.1572; and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6948, Feb. 9, 2005]

**Table 15 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1566(a)(1), you shall meet each emission limitation in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit . . . | You shall meet this emission limit during initial catalyst depressuring and catalyst purging operations . . . |
|---|---|
| 1. Option 1 | Vent emissions to a flare that meets the requirements for control devices in §63.11(b). Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period. |
| 2. Option 2 | Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. If you vent emissions to a boiler or process heater to comply with the percent reduction or concentration emission limitation, the vent stream must be introduced into the flame zone, or any other location that will achieve the percent reduction or concentration standard. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6951, Feb. 9, 2005]

**Table 16 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1566(a)(2), you shall meet each operating limit in the following table that applies to you.

| For each new or existing catalytic reforming unit . . . | For this type of control device . . . | You shall meet this operating limit during initial catalyst depressuring and purging operations. . . |
|---|---|---|
| 1. Option 1: vent to flare | Flare that meets the requirements for control devices in §63.11(b) | The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it. |
| 2. Option 2: Percent reduction or concentration limit | a. Thermal incinerator, boiler or process heater with a design heat input capacity under 44 MW, or boiler or process heater in which all vent streams are not introduced into the flame zone | The daily average combustion zone temperature must not fall below the limit established during the performance test. |
| | b. No control device | Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum catalyst purging conditions that must be met prior to allowing uncontrolled purge releases. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6951, Feb. 9, 2005]

**Table 17 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1566(b)(1), you shall meet each requirement in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit . . . | If you use this type of control device . . . | You shall install and operate this type of continuous monitoring system . . . |
|---|---|---|
| 1. Option 1: vent to a flare | Flare that meets the requirements for control devices in §63.11(b) | Monitoring device such as a thermocouple, an ultraviolet |

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| | | beam sensor, or infrared sensor to continuously detect the presence of a pilot flame. |
| 2. Option 2: percent reduction or concentration limit. | Thermal incinerator, process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into the flame zone | Continuous parameter monitoring systems to measure and record the combustion zone temperature. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6952, Feb. 9, 2005]

**Table 18 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1566(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

| For each new or exiting catalytic reforming unit . . . | You must . . . | Using . . . | According to these requirements . . . |
|---|---|---|---|
| 1. Option 1: Vent to a flare | a. Conduct visible emission observations | Method 22 (40 CFR part 60, appendix A) | 2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test. |
| | b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity | Not applicable. | 40 CFR 63.11(b)(6) through (8). |
| 2. Option 2: Percent reduction or concentration limit | a. Select sampling site | Method 1 or 1A (40 CFR part 60, appendix A). No traverse site selection method is needed for vents smaller than 0.10 meter in diameter. | Sampling sites must be located at the inlet (if you elect the emission reduction standard) and outlet of the control device and prior to any |

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| | | | releases to the atmosphere. |
| | b. Measure gas volumetric flow rate | Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable | |
| | c. Measure TOC concentration (for percent reduction standard) | Method 25 (40 part 60, appendix A) to measure nonmethane TOC concentration (in carbon equivalents) at inlet and outlet of the control device. If the nonmethane TOC outlet concentration is expected to be less than 50 ppm (as carbon), you can use Method 25A to measure TOC concentration (as hexane) at the inlet and the outlet of the control device. If you use Method 25A, you may use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration to determine the nonmethane TOC concentration | Take either an integrated sample or four grab samples during each run. If you use a grab sampling technique, take the samples at approximately equal intervals in time, such as 15-minute intervals during the run. |
| | d. Calculate TOC or nonmethane TOC emission rate and mass emission reduction | | Calculate emission rate by Equation 1 of §63.1566 (if you use Method 25) or Equation 2 of §63.1566 (if you use Method 25A). Calculate mass emission reduction by Equation 3 of §63.1566. |
| | e. For concentration | Method 25A (40 CFR | |

| | | | |
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| | standard, measure TOC concentration. (Optional: Measure methane concentration.) | part 60, appendix A) to measure TOC concentration (as hexane) at the outlet of the control device. You may elect to use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration | |
| | f. Determine oxygen content in the gas stream at the outlet of the control device | Method 3A or 3B (40 CFR part 60, appendix A), as applicable | |
| | g. Calculate the TOC or nonmethane TOC concentration corrected for oxygen content (for concentration standard) | Equation 4 of §63.1566 | |
| | h. Establish each operating limit in Table 16 of this subpart that applies to you for a thermal incinerator, or process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into flame zone | Data from the continuous parameter monitoring systems | Collect the temperature monitoring data every 15 minutes during the entire period of the initial TOC performance test. Determine and record the minimum hourly average combustion zone temperature. |
| | i. If you do not use a control device, document the purging conditions used prior to testing following the minimum requirements in the operation, maintenance, and monitoring plan. | Data from monitoring systems as identified in the operation, maintenance, and monitoring plan | Procedures in the operation, maintenance, and monitoring plan. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6952, Feb. 9, 2005]

**Table 19 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1566(b)(7), you shall meet each requirement in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit . . . | For the following emission limit . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| Option 1 | Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours | Visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes. |
| Option 2 | Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent | The mass emission reduction of nonmethane TOC measured by Method 25 over the period of the performance test is at least 98 percent by weight as calculated using Equations 1 and 3 of §63.1566; or the mass emission reduction of TOC measured by Method 25A (or nonmethane TOC measured by Methods 25A and 18) over the period of the performance test is at least 98 percent by weight as calculated using Equations 2 and 3 of §63.1566; or the TOC concentration measured by Method 25A (or the nonmethane TOC concentration measured by Methods 25A and 18) over the period of the performance test does not exceed 20 ppmv (dry basis as hexane) corrected to 3 percent oxygen as calculated using Equation 4 of §63.1566. |

[70 FR 6953, Feb. 9, 2005]

**Table 20 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit . . . | For this emission limit . . . | You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . . |
|---|---|---|
| 1. Option 1 | Vent emissions from your process vent to a flare that meets the requirements in §63.11(b). | Maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours. |
| 2. Option 2 | Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. | Maintaining a 98 percent by weight emission reduction of TOC or nonmethane TOC; or maintaining a TOC or nonmethane TOC concentration of not more than 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. |

[70 FR 6954, Feb. 9, 2005]

**Table 21 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit . . . | If you use . . . | For this operating limit . . . | You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by . . . |
|---|---|---|---|
| 1. Option 1 | Flare that meets the | The flare pilot light | Collecting flare |

| | | | |
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| | requirements in §63.11(b) | must be present at all times and the flare must be operating at all times that emissions may be vented to it | monitoring data according to §63.1572; and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period. |
| 2. Option 2 | a. Thermal incinerator boiler or process heater with a design input capacity under 44 MW or boiler or process heater in which not all vent streams are not introduced into the flame zone | Maintain the daily average combustion zone temperature above the limit established during the performance test | Collecting, the hourly and daily temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test. |
| | b. No control device | Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum purging conditions that must be met prior to allowing uncontrolled purge releases | Recording information to document compliance with the procedures in your operation, maintenance, and monitoring plan. |

[70 FR 6954, Feb. 9, 2005]

**Table 22 to Subpart UUU of Part 63—Inorganic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1567(a)(1), you shall meet each emission limitation in the following table that applies to you.

| For . . . | You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn-off and catalyst rejuvenation . . . |
|---|---|
| 1. Each existing semi-regenerative catalytic reforming unit | Reduce uncontrolled emissions of hydrogen chloride (HCl) by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen. |

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| 2. Each existing cyclic or continous catalytic reforming unit | Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen. |
| 3. Each new semi-regenerative, cyclic, or continous catalytic reforming unit | Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen. |

[70 FR 6955, Feb. 9, 2005]

**Table 23 to Subpart UUU of Part 63—Operating Limits for Inorganic HAP Emission Limitations for Catalytic Reforming Units**

As stated in §63.1567(a)(2), you shall meet each operating limit in the following table that applies to you.

| For each applicable process vent for a new or existing catalytic reforming unit with this type of control device . . . | You shall meet this operating limit during coke burn-off and catalyst rejuvenation . . . |
|---|---|
| 1. Wet scrubber | The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test. |
| 2. Internal scrubbing system or no control device ( *e.g.* , hot regen system) meeting outlet HCl concentration limit. | The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test. |
| 3. Internal scrubbing system meeting HCl percent reduction standard. | The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test. |
| 4. Fixed-bed gas-solid adsorption system | The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the HCl concentration in the adsorption system exhaust gas must not exceed the limit established during the performance test. |
| 5. Moving-bed gas-solid adsorption system ( *e.g.* , | The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit |

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| Chlorsorb™System). | established during the performance test; and the weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™System); and the weekly average chloride level on the sorbent leaving the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb™System). |

[70 FR 6955, Feb. 9, 2005]

**Table 24 to Subpart UUU of Part 63—Continuous Monitoring Systems for Inorganic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1567(b)(1), you shall meet each requirement in the following table that applies to you.

| If you use this type of control device for your vent . . . | You shall install and operate this type of continuous monitoring system . . . |
|---|---|
| 1. Wet scrubber | Continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the scrubber during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record gas flow rate entering or exiting the scrubber during coke burn-off and catalyst rejuvenation[1]; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation.[2] |
| 2. Internal scrubbing system or no control device (e.g., hot regen system) to meet HC1 outlet concentration limit. | Colormetric tube sampling system to measure the HC1 concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart. |
| 3. Internal scrubbing system to meet HC1 percent reduction standard | Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter |

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| | monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation.[2] |
| 4. Fixed-bed gas-solid adsorption system | Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation; and colormetric tube sampling system to measure the gaseous HC1 concentration in the adsorption system exhaust and at a point within the absorbent bed not to exceed 90 percent of the total length of the absorbent bed during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart. |
| 5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™System). | Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation. |

[1]If applicable, you can use the alternative in §63.1573 (a)(1) instead of a continuous parameter monitoring system for gas flow rate or instead of a continuous parameter monitoring system for the cumulative volume of gas.

[2]If applicable, you can use the alternative in §63.1573(b)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in §63.1573(b)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).

[70 FR 6956, Feb. 9, 2005]

**Table 25 to Subpart UUU of Part 63—Requirements for Performance Tests for Inorganic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1567(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic reforming unit using . . . | You shall . . . | Using . . . | According to these requirements . . . |
|---|---|---|---|
| 1. Any or no control system | a. Select sampling port location(s) and the number of | Method 1 or 1A (40 CFR part 60, appendix A), as applicable. | (1) If you operate a control device and you elect to meet an applicable HCl percent |

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| | traverse points | | reduction standard, sampling sites must be located at the inlet of the control device or internal scrubbing system and at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. |
| | | | (2) If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere. |
| | b. Determine velocity and volumetric flow | Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as | |

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| | rate. | applicable. | |
| | c. Conduct gas molecular weight analysis. | Method 3, 3A, or 3B (40 CFR part 60, appendix A), as applicable | |
| | d. Measure moisture content of the stack gas | Method 4 (40 CFR part 60, appendix A) | |
| | e. Measure the HCl concentration at the selected sampling locations | Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A | (1) For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi-regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up. |
| | | | (2) Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of §63.1567) for each sampling location for each test run. |
| | | | (3) Determine and record the percent emission reduction, if applicable, using |

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| | | | Equation 3 of §63.1567 for each test run. |
| | | | (4) Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values. |
| 2. Wet scrubber | a. Establish operating limit for pH level or alkalinity | i. Data from continuous parameter monitoring systems | Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values. |
| | | ii. Alternative pH procedure in §63.1573 (b)(1). | Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level. |
| | | iii. Alternative alkalinity method in §63.1573(b)(2) | Measure and record the alkalinity of the water (or scrubbing liquid) |

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| | | | exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level. |
| | b. Establish operating limit for liquid-to-gas ratio. | i. Data from continuous parameter monitoring systems | Measure and record the gas flow rate entering or exiting the scrubber and the total water (or scrubbing liquid) flow rate entering the scrubber every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values. |
| | | ii. Alternative procedure for gas flow rate in §63.1573(a)(1) | Collect air flow rate monitoring data or determine the air flow rate using control room instruments every 15 minutes during the entire period of the initial performance test. Determine and record the hourly average rate of all the readings. |

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| | | | Determine and record the maximum gas flow rate using Equation 1 of §63.1573. |
| 3. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl outlet concentration limit. | Establish operating limit for HCl concentration. | Data from continuous parameter monitoring system. | Measure and record the HCl concentration in the catalyst regenerator exhaust gas using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. Determine and record the operating limit for HCl concentration using Equation 4 of §63.1567. |
| 4. Internal scrubbing system meeting HCl percent reduction standard | a. Establish operating limit for pH level or alkalinity | i. Data from continuous parameter monitoring system | Measure and record the pH alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values. |
| | | ii. Alternative pH method in §63.1573(b)(1) | Measure and in record pH of the water (or scrubbing liquid) exiting the internal scrubbing system |

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| | | | during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level. |
| | | iii. Alternative alkalinity method in §63.1573(b)(2) | Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level. |
| | b. Establish operating limit for liquid-to-gas ratio | Data from continuous parameter monitoring systems | Measure and record the gas entering or exiting the internal scrubbing system and the total water (or scrubbing liquid) flow rate entering the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing |

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| | | | liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values. |
| 5. Fixed-bed gas-solid adsorption system. Gas-solid | a. Establish operating limit for temperature | Data from continuous parameter monitoring system | Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature. |
| | b. Establish operating limit for HCl concentration | i. Data from continuous parameter monitoring systems | (1) Measure and record the HCl concentration in the exhaust gas from the fixed-bed adsorption system using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. |
| | | | (2) If you elect to comply with the HCl outlet concentration limit (Option 2), determine and record the operating limit for HCl concentration using Equation 4 of §63.1567. If you elect to comply with the HCl percent reduction standard (Option 1), determine and record |

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| | | | the operating limit for HCl concentration using Equation 5 of §63.1567. |
| 6. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™System) | a. Establish operating limit for temperature | Data from continuous parameter monitoring systems. | Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature. |
| | b. Measure the chloride level on the sorbent entering and exiting the adsorption system. | Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to subpart UUU; or EPA Method 5050 combined either with EPA Method 9056, or with EPA Method 9253; or EPA Method 9212 with the soil extraction procedures listed within the method.[1] | Measure and record the chloride concentration of the sorbent material entering and exiting the adsorption system at least three times during each test run. Determine and record the average weight percent chloride concentration of the sorbent entering the adsorption system for each test run. Determine and record the average weight percent chloride concentration of the sorbent exiting the adsorption system for each test run. |

[1]The EPA Methods 5050, 9056, 9212 and 9253 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm.*

[70 FR 6956, Feb. 9, 2005]

**Table 26 to Subpart UUU of Part 63—Initial Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1567(b)(4), you shall meet each requirement in the following table that applies to you.

| For . . . | For the following emission limit . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| 1. Each existing semi-regenerative catalytic reforming unit | Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv, (dry basis), corrected to 3 percent oxygen. | Average emissions HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 92 percent or to a concentration less than or equal to 30 ppmv (dry basis) corrected to 3 percent oxygen. |
| 2. Each existing cyclic or continuous catalytic reforming unit and each new semi-regenerative, cyclic, or continuous catalytic reforming unit. | Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen | Average emissions of HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 97 percent or to a concentration less than or equal to 10 ppmv (dry basis) corrected to 3 percent oxygen. |

[70 FR 6959, Feb. 9, 2005]

**Table 27 to Subpart UUU of Part 63—Continuous Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units**

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

| For . . . | For this emission limit . . . | You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . . |
|---|---|---|
| 1. Each existing semi-regenerative catalytic reforming unit | Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen. | Maintaining a 92 percent HCl emission reduction or an HCl concentration no more than 30 ppmv (dry basis), corrected to 3 percent oxygen. |
| 2. Each existing cyclic or continuous catalytic reforming unit | Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen | Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen. |

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| 3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit | Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen | Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen. |

[70 FR 6960, Feb. 9, 2005]

**Table 28 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Inorganic HAP Emissions From Catalytic Reforming Units**

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

| For each new and existing catalytic reforming unit using this type of control device or system . . . | For this operating limit . . . | You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . . |
|---|---|---|
| 1. Wet scrubber | a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the level established during the performance test | Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572[1]; and maintaining the daily average pH or alkalinity above the operating limit established during the performance test. |
| | b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test | Collecting the hourly average gas flow rate[2]and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test. |
| 2. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl concentration limit | The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test | Measuring and recording the HCl concentration at least 4 times during a regeneration cycle (equally spaced in time) or every 4 hours, whichever is more frequent, using a colormetric tube sampling system; |

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| | | calculating the daily average HCl concentration as an arithmetic average of all samples collected in each 24-hour period from the start of the coke burn-off cycle or for the entire duration of the coke burn-off cycle if the coke burn-off cycle is less than 24 hours; and maintaining the daily average HCl concentration below the applicable operating limit. |
| 3. Internal scrubbing system meeting percent HCl reduction standard | a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test | Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572[1]and maintaining the daily average pH or alkalinity above the operating limit established during the performance test. |
| | b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test | Collecting the hourly average gas flow rate[2]and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test. |
| 4. Fixed-bed gas-solid adsorption systems | a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test | Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test. |
| | b. The HCl concentration in the exhaust gas from the fixed-bed gas-solid adsorption system must not exceed the limit established | Measuring and recording the concentration of HCl weekly or during each regeneration cycle, whichever is less frequent, using a colormetric tube sampling system at |

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| | during the performance test | a point within the adsorbent bed not to exceed 90 percent of the total length of the adsorption bed during coke-burn-off and catalyst rejuvenation; implementing procedures in the operating and maintenance plan if the HCl concentration at the sampling location within the adsorption bed exceeds the operating limit; and maintaining the HCl concentration in the gas from the adsorption system below the applicable operating limit. |
| 5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™System | a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test | Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test. |
| | b. The weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Clorsorb™ | Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride[3]; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb™System). |
| | c. The weekly average chloride level on the sorbent exiting the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Clorsorb™System) | Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride concentration; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the |

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| | | design or manufacturer's recommended limit (1.8 weight percent Chlorsorb™System). |

[1]If applicable, you can use either alternative in §63.1573(b) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test.

[2]If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for the gas flow rate or cumulative volume of gas entering or exiting the system if you used the alternative method in the initial performance test.

[3]The total chloride concentration of the sorbent material must be measured by the procedure, "Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)" in appendix A to this subpart; or by using EPA Method 5050, Bomb Preparation Method for Solid Waste, combined either with EPA Method 9056, Determination of Inorganic Anions by Ion Chromatography, or with EPA Method 9253, Chloride (Titrimetric, Silver Nitrate); or by using EPA Method 9212, Potentiometric Determination of Chloride in Aqueous Samples with Ion-Selective Electrode, and using the soil extraction procedures listed within the method. The EPA Methods 5050, 9056, 9212 and 9253 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Revision 5 (April 1998). The SW–846 and Updates (document number 955–001–00000–1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487–4650. Copies may be inspected at the EPA Docket Center (Air Docket), EPA West, Room B–108, 1301 Constitution Ave., NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm* .

[70 FR 6954, Feb. 9, 2005]

**Table 29 to Subpart UUU of Part 63—HAP Emission Limits for Sulfur Recovery Units**

As stated in §63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

| For . . . | You shall meet this emission limit for each process vent . . . |
|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2). | a. 250 ppmv (dry basis) of sulfur dioxide ($SO_2$) at zero percent excess air if you use an oxidation or reduction control system followed by incineration.<br>b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration. |
| 2. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2): Option 1 (Elect NSPS). | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration. |

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| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration. |
| 3. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in paragraph (a)(2) of 40 CFR 60.104: Option 2 (TRS limit). | 300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent $SO_2$concentration (dry basis) at zero percent oxygen. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 30 to Subpart UUU of Part 63—Operating Limits for HAP Emissions From Sulfur Recovery Units**

As stated in §63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

| For . . . | If use this type of control device | You shall meet this operating limit. . . |
|---|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2). | Not applicable | Not applicable. |
| 2. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2): Option 1 (Elect NSPS). | Not applicable | Not applicable. |
| 3. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2): Option 2 (TRS limit). | Thermal incinerator | Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 31 to Subpart UUU of Part 63—Continuous Monitoring Systems for HAP Emissions From Sulfur Recovery Units**

As stated in §63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

| For . . . | For this limit . . . | You shall install and operate this continuous monitoring system . . . |
|---|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration | Continuous emission monitoring system to measure and record the hourly average concentration of $SO_2$(dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air. |
| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration | Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen ($O_2$) emissions. Calculate the reduced sulfur emissions as $SO_2$(dry basis) at zero percent excess air. *Exception:* You can use an instrument having an air or $SO_2$dilution and oxidation system to convert the reduced sulfur to $SO_2$for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant $SO_2$instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen. |
| 2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in paragraph (a) (2) of 40 CFR 60.104 | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration | Continuous emission monitoring system to measure and record the hourly average concentration of $SO_2$(dry basis), at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air. |

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| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration. | Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and $O_2$emissions for each exhaust stack. Calculate the reduced sulfur emissions as $SO_2$(dry basis), at zero percent excess air. *Exception:* You can use an instrument having an air or $O_2$dilution and oxidation system to convert the reduced sulfur to $SO_2$for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant $SO_2$instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen. |
| 3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | 300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent $SO_2$concentration (dry basis) at zero percent oxygen | i. Continuous emission monitoring system to measure and record the hourly average concentration of TRS for each exhaust stack; this monitor must include an oxygen monitor for correcting the data for excess oxygen; or |
| | | ii. Continuous parameter monitoring systems to measure and record the combustion zone temperature of each thermal incinerator and the oxygen content (percent, dry basis) in the vent stream of the incinerator. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6961, Feb. 9, 2005]

**Table 32 to Subpart UUU of Part 63—Requirements for Performance Tests for HAP Emissions From Sulfur Recovery Units Not Subject to the New Source Performance Standards for Sulfur Oxides**

As stated in §63.1568(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

| For . . . | You must . . . | Using . . . | According to these requirements . . . |
|---|---|---|---|
| 1. Each new and existing sulfur recovery unit: Option 1 (Elect NSPS). | Measure $SO_2$concentration (for an oxidation or reduction system followed by incineration) or the concentration of reduced sulfur (or $SO_2$if you use an instrument to convert the reduced sulfur to $SO_2$) for a reduction control system without incineration. | Data from continuous emission monitoring system. | Collect $SO_2$monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period. |
| 2. Each new and existing sulfur recovery unit: Option 2 (TRS limit). | a. Select sampling port's location and the number of traverse ports. | Method 1 or 1A appendix A to part 60 of this chapter. | Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere. |
| | b. Determine velocity and volumetric flow rate. | Method 2, 2A, 2C, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable. | |
| | c. Conduct gas molecular weight analysis; obtain the oxygen concentration needed to correct the emission rate for excess air. | Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable. | Take the samples simultaneously with reduced sulfur or moisture samples. |
| | d. Measure moisture content of the stack gas. | Method 4 in appendix A to part 60 of this chapter. | Make your sampling time for each Method 4 sample equal to that for 4 Method 15 samples. |
| | e. Measure the concentration of TRS. | Method 15 or 15A in appendix A to part 60 of this chapter, as | If the cross-sectional area of the duct is less than 5 square meters ($m^2$) or 54 square feet, you must use the |

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| | | applicable. | centroid of the cross section as the sampling point. If the cross-sectional area is 5 $m^2$or more and the centroid is more than 1 meter (m) from the wall, your sampling point may be at a point no closer to the walls than 1 m or 39 inches. Your sampling rate must be at least 3 liters per minute or 0.10 cubic feet per minute to ensure minimum residence time for the sample inside the sample lines. |
| | f. Calculate the $SO_2$equivalent for each run after correcting for moisture and oxygen. | The arithmetic average of the $SO_2$equivalent for each sample during the run. | |
| | g. Correct the reduced sulfur samples to zero percent excess air.sa | Equation 1 of §63.1568. | |
| | h. Establish each operating limit in Table 30 of this subpart that applies to you. | Data from the continuous parameter monitoring system. | |
| | i. Measure thermal incinerator: combustion zone temperature. | Data from the continuous parameter monitoring system. | Collect temperature monitoring data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average temperature from all the readings. |
| | j. Measure thermal incinerator: oxygen concentration (percent, dry basis) in the vent stream. | Data from the continuous parameter monitoring system. | Collect oxygen concentration (percent, dry basis) data every 15 minutes during the entire period of the performance test; and determine and record the |

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| | | | minimum hourly average percent excess oxygen concentration. |
| | k. If you use a continuous emission monitoring system, measure TRS concentration. | Data from continuous emission monitoring system. | Collect TRS data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 33 to Subpart UUU of Part 63—Initial Compliance With HAP Emission Limits for Sulfur Recovery Units**

As stated in §63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

| For . . . | For the following emission limit . . . | You have demonstrated initial compliance if . . . |
|---|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | a. 250 pmv (dry basis) $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration | You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of $SO_2$emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the $SO_2$limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. |

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| | | You are not required to do another performance evaluation to demonstrate initial compliance. |
| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration | You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv $SO_2$(dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the $SO_2$limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to do another performance evaluation to demonstrate initial compliance. |
| 2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration | Each 12-hour rolling average concentration of $SO_2$emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 250 ppmv (dry basis) at zero percent excess air; and your performance evaluation shows the monitoring system meets the applicable requirements in §63.1572. |
| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv | Each 12-hour rolling average concentration of reduced sulfur compounds measured by the |

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| | $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration | continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv, calculated as ppmv $SO_2$(dry basis) at zero percent excess air; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572. |
| 3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | 300 ppmv of TRS compounds expressed as an equivalent $SO_2$concentration (dry basis) at zero percent oxygen | If you use continuous parameter monitoring systems, the average concentration of TRS emissions measured using Method 15 during the initial performance test is less than or equal to 300 ppmv expressed as equivalent $SO_2$concentration (dry basis) at zero percent oxygen. If you use a continuous emission monitoring system, each 12-hour rolling average concentration of TRS emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv expressed as an equivalent $SO_2$(dry basis) at zero percent oxygen; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572. |

[70 FR 6962, Feb. 9, 2005]

**Table 34 to Subpart UUU of Part 63—Continuous Compliance With HAP Emission Limits for Sulfur Recovery Units**

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

| For . . . | For this emission limit . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or | Collecting the hourly average $SO_2$monitoring data (dry basis, percent excess air) according to |

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| recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2). | reduction control system followed by incineration. | §63.1572; determining and recording each 12-hour rolling average concentration of $SO_2$; maintaining each 12-hour rolling average concentration of $SO_2$at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of $SO_2$greater than the applicable emission limitation in the compliance report required by §63.1575. |
| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration. | Collecting the hourly average reduced sulfur (and air or $O_2$dilution and oxidation) monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the compliance report required by §63.1575. |
| 2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2). | a. 250 ppmv (dry basis) of $SO_2$at zero percent excess air if you use an oxidation or reduction control system followed by incineration. | Collecting the hourly average $SO_2$data (dry basis, percent excess air) according to §63.1572; determining and recording each 12-hour rolling average concentration of $SO_2$; maintaining each 12-hour rolling average concentration of $SO_2$at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of $SO_2$greater than the applicable emission limitation in the compliance report required by |

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| | | §63.1575. |
| | b. 300 ppmv of reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air if you use a reduction control system without incineration. | Collecting the hourly average reduced sulfur (and air or $O_2$dilution and oxidation) monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the compliance report required by §63.1575. |
| 3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2). | 300 ppmv of TRS compounds, expressed as an $SO_2$concentration (dry basis) at zero percent oxygen or reduced sulfur compounds calculated as ppmv $SO_2$(dry basis) at zero percent excess air. | i. If you use continuous parameter monitoring systems, collecting the hourly average TRS monitoring data according to §63.1572 and maintaining each 12-hour average concentration of TRS at or below the applicable emission limitation; or |
| | | ii. If you use a continuous emission monitoring system, collecting the hourly average TRS monitoring data according to §63.1572, determining and recording each 12-hour rolling average concentration of TRS; maintaining each 12-hour rolling average concentration of TRS at or below the applicable emission limitation; and reporting any 12-hour rolling average TRS concentration greater than the applicable emission limitation in the compliance report required by §63.1575. |

[70 FR 6963, Feb. 9, 2005]

**Table 35 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for HAP Emissions From Sulfur Recovery Units**

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

| For . . . | For this operating limit . . . | You shall demonstrate continuous compliance by . . . |
|---|---|---|
| 1. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant of 20 long tons per day or more and subject to the NSPS for sulfur oxides in paragraph 40 CFR 60.104(a)(2). | Not applicable | Meeting the requirements of Table 34 of this subpart. |
| 2. Option 1: Elect NSPS Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | Not applicable | Meeting the requirements of Table 34 of this subpart. |
| 3. Option 2: TRS limit Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) | a. Maintain the daily average combustion zone temperature above the level established during the performance test. | Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature at or above the limit established during the performance test. |
| | b. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test. | Collecting the hourly and daily average $O_2$monitoring data according to §63.1572; and maintaining the average $O_2$concentration above the level established during the performance test. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 36 to Subpart UUU of Part 63—Work Practice Standards for HAP Emissions From Bypass Lines**

As stated in §63.1569(a)(1), you shall meet each work practice standard in the following table that applies to you.

| Option | You shall meet one of these equipment standards . . . |
|---|---|
| 1. Option 1 | Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere. |
| 2. Option 2 | Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device. |
| 3. Option 3 | Seal the bypass line by installing a solid blind between piping flanges. |
| 4. Option 4 | Vent the bypass line to a control device that meets the appropriate requirements in this subpart. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6964, Feb. 9, 2005]

**Table 37 to Subpart UUU of Part 63—Requirements for Performance Tests for Bypass Lines**

As stated in §63.1569(b)(1), you shall meet each requirement in the following table that applies to you.

| For this standard . . . | You shall . . . |
|---|---|
| 1. Option 1: Install and operate a flow indicator, level recorder, or electronic valve position monitor. | Record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 38 to Subpart UUU of Part 63—Initial Compliance With Work Practice Standards for HAP Emissions from Bypass Lines**

As stated in §63.1569(b)(2), you shall meet each requirement in the following table that applies to you.

| Option . . . | For this work practice standard . . . | You have demonstrated |
|---|---|---|

| | | **initial compliance if . . .** |
|---|---|---|
| 1. Each new or existing bypass line associated with a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit | a. Option 1: Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere | The installed equipment operates properly during each run of the performance test and no flow is present in the line during the test. |
| | b. Option 2: Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device | As part of the notification of compliance status, you certify that you installed the equipment, the equipment was operational by your compliance date, and you identify what equipment was installed. |
| | c. Option 3: Seal the bypass line by installing a solid blind between piping flanges | See item 1.b of this table. |
| | d. Option 4: Vent the bypass line to a control device that meets the appropriate requirements in this subpart | See item 1.b of this table. |

[70 FR 6965, Feb. 9, 2005]

**Table 39 to Subpart UUU of Part 63—Continuous Compliance With Work Practice Standards for HAP Emissions From Bypass Lines**

As stated in §63.1569(c)(1), you shall meet each requirement in the following table that applies to you.

| **If you elect this standard . . .** | **You shall demonstrate continuous compliance by . . .** |
|---|---|
| 1. Option 1: Flow indicator, level | Monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting |

| | |
|---|---|
| recorder, or electronic valve position monitor. | the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line. |
| 2. Option 2: Car-seal or lock-and-key device | Visually inspecting the seal or closure mechanism at least once every month; and recording whether the bypass line valve is maintained in the closed position and whether flow is present in the line. |
| 3. Option 3: Solid blind flange | Visually inspecting the blind at least once a month; and recording whether the blind is maintained in the correct position such that the vent stream cannot be diverted through the bypass line. |
| 4. Option 4: Vent to control device | Monitoring the control device according to appropriate subpart requirements. |
| 5. Option 1, 2, 3, or 4 | Recording and reporting the time and duration of any bypass. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6965, Feb. 9, 2005]

**Table 40 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Opacity Monitoring Systems and Continuous Emission Monitoring Systems**

As stated in §63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

| This type of continuous opacity or emission monitoring system . . . | Must meet these requirements . . . |
|---|---|
| 1. Continuous opacity monitoring system | Performance specification 1 (40 CFR part 60, appendix B). |
| 2. CO continuous emission monitoring system | Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly. |
| 3. CO continuous emission monitoring system used to demonstrate emissions average under 50 ppm (dry basis). | Performance specification 4 (40 CFR part 60, appendix B); and span value of 100 ppm. |
| 4. $SO_2$continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must | Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm $SO_2$; use Methods 6 or 6C and 3A or 3B (40 CFR part 60, appendix A) for certifying $O_2$monitor; and |

| | |
|---|---|
| include an $O_2$monitor for correcting the data for excess air. | procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly. |
| 5. Reduced sulfur and $O_2$continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an $O_2$monitor for correcting the data for excess air unless exempted. | Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; 450 ppm reduced sulfur; use Methods 15 or 15A and 3A or 3B (40 CFR part 60, appendix A) for certifying $O_2$monitor; if Method 3A or 3B yields $O_2$concentrations below 0.25 percent during the performance evaluation, the $O_2$concentration can be assumed to be zero and the $O_2$monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly. |
| 6. Instrument with an air or $O_2$dilution and oxidation system to convert reduced sulfur to $SO_2$for continuously monitoring the concentration of $SO_2$instead of reduced sulfur monitor and $O_2$monitor. | Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm $SO_2$; use Methods 15 or 15A and 3A or 3B for certifying $O_2$monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly. |
| 7. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an $O_2$monitor for correcting the data for excess air. | Performance specification 5 (40 CFR part 60, appendix B). |
| 8. $O_2$monitor for oxygen concentration. | If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60, appendix B; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly. |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942 and 6965, Feb. 9, 2005]

**Table 41 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Parameter Monitoring Systems**

As stated in §63.1572(c)(1), you shall meet each requirement in the following table that applies to you.

| If you use . . . | You shall . . . |
|---|---|
| 1. pH strips | Use pH strips with an accuracy of ±10 percent. |
| 2. Colormetric tube sampling system | Use a colormetric tube sampling system with a printed numerical scale in ppmv, a standard measurement range of 1 to 10 ppmv (or 1 to 30 ppmv if applicable), and a standard deviation for measured values of no more than ±15 percent. System must include a gas detection pump and hot air probe if needed for the measurement range. |

[70 FR 6966, Feb. 9, 2005]

**Table 42 to Subpart UUU of Part 63—Additional Information for Initial Notification of Compliance Status**

As stated in §63.1574(d), you shall meet each requirement in the following table that applies to you.

| For . . . | You shall provide this additional information . . . |
|---|---|
| 1. Identification of affected sources and emission points. | Nature, size, design, method of operation, operating design capacity of each affected source; identify each emission point for each HAP; identify any affected source or vent associated with an affected source not subject to the requirements of subpart UUU. |
| 2. Initial compliance | Identification of each emission limitation you will meet for each affected source, including any option you select (i.e., NSPS, PM or Ni, flare, percent reduction, concentration, options for bypass lines); if applicable, certification that you have already conducted a performance test to demonstrate initial compliance with the NSPS for an affected source; certification that the vents meet the applicable emission limit and the continuous opacity or that the emission monitoring system meets the applicable performance specification; if applicable, certification that you have installed and verified the operational status of equipment by your compliance date for each bypass line that meets the requirements of Option 2, 3, or 4 in §63.1569 and what equipment you installed; identification of the operating limit for each affected source, including supporting documentation; if your affected source is subject to the NSPS, certification of compliance with NSPS emission limitations and performance specifications; a brief description of performance test conditions (capacity, feed quality, catalyst, etc.); an engineering assessment (if applicable); and if applicable, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the Method 22 test. |

| | |
|---|---|
| 3. Continuous compliance | Each monitoring option you elect; and identification of any unit or vent for which monitoring is not required; and the definition of "operating day." (This definition, subject to approval by the applicable permitting authority, must specify the times at which a 24-hr operating day begins and ends.) |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 43 to Subpart UUU of Part 63—Requirements for Reports**

As stated in §63.1575(a), you shall meet each requirement in the following table that applies to you.

| You must submit a(n) . . . | The report must contain . . . | You shall submit the report . . . |
|---|---|---|
| 1. Compliance report | If there are not deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; | Semiannually according to the requirements in §63.1575(b). |
| | and if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in §63.1575(d) or (e) | |

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

**Table 44 to Subpart UUU of Part 63—Applicability of NESHAP General Provisions to Subpart UUU**

As stated in §63.1577, you shall meet each requirement in the following table that applies to you.

| Citation | Subject | Applies to supbart UUU | Explanation |
|---|---|---|---|
| §63.1 | Applicability | Yes | Except that subpart UUU specifies calendar or operating day. |
| §63.2 | Definitions | Yes | |

| | | | |
|---|---|---|---|
| §63.3 | Units and Abbreviations | Yes | |
| §63.4 | Prohibited Activities | Yes | |
| §63.5(A)–(C) | Construction and Reconstruction | Yes | In §63.5(b)(4), replace the reference to §63.9 with §63.9(b)(4) and (5). |
| §63.5(d)(1)(i) | Application for Approval of Construction or Reconstruction—General Application Requirements | Yes | Except, subpart UUU specifies the application is submitted as soon as practicable before startup but not later than 90 days (rather then 60) after the promulgation date where construction or reconstruction had commenced and initial startup had not occurred before promulgation. |
| §63.5(d)(1)(ii) | | Yes | Except that emission estimates specified in §63.5(d)(1)(ii)(H) are not required. |
| §63.5(d)(1)(iii) | | No | Subpart UUU specifies submission of notification of compliance status. |
| §63.5(d)(2) | | No | |
| §63.5(d)(3) | | Yes | Except that §63.5(d)(3)(ii) does not apply. |
| §63.5(d0(4) | | Yes | |
| §63.5(e) | Approval of Construction or Reconstruction | Yes | |
| §63.5(f)(1) | Approval of Construction or Reconstruction Based on State Review | | |
| §63.5(f)(2) | | Yes | Except that 60 days is changed to 90 days and cross-reference to 53.9(B)(2) does not apply. |

| | | | |
|---|---|---|---|
| §63.6(a) | Compliance with Standards and Maintenance—Applicability | Yes | |
| §63.6(b)(1)–(4) | Compliance Dates for New and Reconstructed Sources | Yes | |
| §63.6(b)(5) | | Yes | Except that subpart UUU specifies different compliance dates for sources. |
| §63.6(b)(6) | [Reserved] | Not applicable | |
| §63.6(b)(7) | Compliance Dates for New and Reconstructed Area Sources That Become Major | Yes | |
| §63.6(c)(1)–(2) | Compliance Dates for Existing Sources | Yes | Except that subpart UUU specifies different compliance dates for sources subject to Tier II gasoline sulfur control requirements. |
| §63.6(c)(3)–(4) | [Reserved] | Not applicable | |
| §63.6(c)(5) | Compliance Dates for Existing Area Sources That Become Major | Yes | |
| §63.6(d) | [Reserved] | Not applicable | |
| §63.6(e)(1)–(2) | Operation and Maintenance Requirements | Yes | |
| §63.6(e)(3)(i)–(iii) | Startup, Shutdown, and Malfunction Plan | Yes | |
| §63.6(e)(3)(iv) | | Yes | Except that reports of actions not consistent with plan are not required within 2 and 7 days of action but rather must be included in next periodic report. |
| §63.6(e)(3)(v)– | | Yes | The owner or operator is |

| | | | |
|---|---|---|---|
| (viii) | | | only required to keep the latest version of the plan. |
| §63.6(e)(3)(ix) | | Yes | |
| §63.6(f)(1)–(2)(iii)(C) | Compliance with Emission Standards | Yes | |
| §63.6(f)(2)(iii)(D) | | No | |
| §63.6(f)(2)(iv)–(v) | | Yes | |
| §63.6(f)(3) | | Yes | |
| §63.6(g) | Alternative Standard | Yes | |
| §63.6(h) | Opacity/VE Standards | Yes | |
| §63.6(h)(2)(i) | Determining Compliance with Opacity/VE Standards | No | Subpart UUU specifies methods. |
| §63.6(h)(2)(ii) | [Reserved] | Not applicable | |
| §63.6(h)(2)(iii) | | Yes | |
| §63.6(h)(3) | [Reserved] | Not applicable | |
| §63.6(h)(4) | Notification of Opacity/VE Observation Date | Yes | Applies to Method 22 tests. |
| §63.6(h)(5) | Conducting Opacity/VE Observations | No | |
| §63.6(h)(6) | Records of Conditions During Opacity/VE Observations | Yes | Applies to Method 22 observations. |
| §63.6(h)(7)(i) | Report COM Monitoring Data from Performance Test | Yes | |
| §63.6(h)(7)(ii) | Using COM Instead of Method 9 | No | |
| §63.6(h)(7)(iii) | Averaging Time for COM during Performance Test | Yes | |
| §63.6(h)(7)(iv) | COM Requirements | Yes | |

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|---|---|---|---|
| §63.6(h)(8) | Determining Compliance with Opacity/VE Standards | Yes | |
| §63.6(h)(9) | Adjusted Opacity Standard | Yes | |
| §63.6(i)(1)–(14) | Extension of Compliance | Yes | Extension of compliance under §63.6(i)(4) not applicable to a facility that installs catalytic cracking feed hydrotreating and receives an extended compliance date under §63.1563(c). |
| §63.6(i)(15) | [Reserved] | Not applicable | |
| §63.6(i)(16) | | Yes | |
| §63.6(j) | Presidential Compliance Exemption | Yes | |
| §63.7(a)(1) | Performance Test Requirements Applicability | Yes | Except that subpart UUU specifies the applicable test and demonstration procedures. |
| §63.7(a)(2) | Performance Test Dates | No | Test results must be submitted in the Notification of Compliance Status report due 150 days after the compliance date. |
| §63.7(a)(3) | Section 114 Authority | Yes | |
| §63.7(b) | Notifications | Yes | Except that subpart UUU specifies notification at least 30 days prior to the scheduled test date rather than 60 days. |
| §63.7(c) | Quality Assurance Program/Site-Specific Test Plan | Yes | |
| §63.7(d) | Performance Test Facilities | Yes | |
| §63.7(e) | Conduct of Tests | Yes | |

| | | | |
|---|---|---|---|
| §63.7(f) | Alternative Test Method | Yes | |
| §63.7(g) | Data Analysis, Recordkeeping, Reporting | Yes | Except performance test reports must be submitted with notification of compliance status due 150 days after the compliance date. |
| §63.7(h) | Waiver of Tests | Yes | |
| §63.8(a)(1) | Monitoring Requirements-Applicability | Yes | |
| §63.8(a)(2) | Performance Specifications | Yes | |
| §63.8(a)(3) | [Reserved] | Not applicable | |
| §63.8(a)(4) | Monitoring with Flares | Yes | |
| §63.8(b)(1) | Conduct of Monitoring | Yes | |
| §63.8(b)(2)–(3) | Multiple Effluents and Multiple Monitoring Systems | Yes | Subpart UUU specifies the required monitoring locations. |
| §63.8(c)(1) | Monitoring System Operation and Maintenance | Yes | |
| §63.8(c)(1)(i)–(ii) | Startup, Shutdown, and Malfunctions | Yes | Except that subpart UUU specifies that reports are not required if actions are consistent with the SSM plan, unless requested by the permitting authority. If actions are not consistent, actions must be described in next compliance report. |
| §63.8(c)(1)(iii) | Compliance with Operation and Maintenance Requirements | Yes | |
| §63.8(c)(2)–(3) | Monitoring System Installation | Yes | Except that subpart UUU specifies that for continuous parameter monitoring systems, operational status verification includes |

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| | | | completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately. |
| §63.8(c)(4) | Continuous Monitoring System Requirements | No | Subpart UUU specifies operational requirements. |
| §63.8(c)(4)(i)–(ii) | Continuous Monitoring System Requirements | Yes | Except that these requirements apply only to a continuous opacity monitoring system or a continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. |
| §63.8(c)(5) | COM Minimum Procedures | Yes | |
| §63.8(c)(6) | CMS Requirements | No | Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. |
| §63.8(c)(7)–(8) | CMS Requirements | Yes | |
| §63.8(d) | Quality Control Program | Yes | Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. |
| §63.8(e) | CMS Performance | Yes | Except that these |

| | | | |
|---|---|---|---|
| | Evaluation | | requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. Results are to be submitted as part of the Notification Compliance Status due 150 days after the compliance date. |
| §63.8(f)(1)–(5) | Alternative Monitoring Methods | Yes | Except that subpart UUU specifies procedures for requesting alternative monitoring systems and alternative parameters. |
| §63.8(f)(6) | Alternative to Relative Accuracy Test | Yes | Applicable to continuous emission monitoring systems if performance specification requires a relative accuracy test audit. |
| §63.8(g)(1)–(4) | Reduction of Monitoring Data | Yes | Applies to continuous opacity monitoring system or continuous emission monitoring system. |
| §63.8(g)(5) | Data Reduction | No | Subpart UUU specifies requirements. |
| §63.9(a) | Notification Requirements—Applicability | Yes | Duplicate Notification of Compliance Status report to the Regional Administrator may be required. |
| §63.9(b)(1)–(2), (4)–(5) | Initial Notifications | Yes | Except that notification of construction or reconstruction is to be submitted as soon as practicable before startup but no later than 30 days (rather than 60 days) after the |

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|---|---|---|---|
| | | | effective date if construction or reconstruction had commenced but startup had not occurred before the effective date. |
| §63.9(b)(3) | [Reserved] | | |
| §63.9(c) | Request for Extension of Compliance | Yes | |
| §63.9(d) | New Source Notification for Special Compliance Requirements | Yes | |
| §63.9(e) | Notification of Performance Test | Yes | Except that notification is required at least 30 days before test. |
| §63.9(f) | Notification of VE/Opacity Test | Yes | |
| §63.9(g) | Additional Notification Requirements for Sources with Continuous Monitoring Systems | Yes | Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. |
| §63.9(h) | Notification of Compliance Status | Yes | Except that subpart UUU specifies the notification is due no later than 150 days after compliance date. |
| §63.9(i) | Adjustment of Deadlines | Yes | |
| §63.9(j) | Change in Previous Information | Yes | |
| 63.10(a) | Recordkeeping and Reporting Applicability | Yes | |
| §63.10(b) | Records | Yes | Except that §63.10(b)(2)(xiii) applies if you use a continuous emission |

| | | | |
|---|---|---|---|
| | | | monitoring system to meet the NSPS or you select to meet the NSPS, CO, or $SO_2$reduced sulfur limit and the performance evaluation requires a relative accuracy test audit. |
| §63.10(c)(1)–(6), (9)–(15) | Additional Records for Continuous Monitoring Systems | Yes | Except that these requirements apply if you use a continuous opacity monitoring system or a continuous emission monitoring system to meet the NSPS or elect to meet the NSPS opacity, CO, or $SO_2$limits. |
| §63.10(c)(7)–(8) | Records of Excess Emissions and Exceedances | No | Subpart UUU specifies requirements. |
| §63.10(d)(1) | General Reporting Requirements | Yes | |
| §63.10(d)(2) | Performance Test Results | No | Subpart UUU requires performance test results to be reported as part of the Notification of Compliance Status due 150 days after the compliance date. |
| §63.10(d)(3) | Opacity or VE Observations | Yes | |
| §63.10(d)(4) | Progress Reports | Yes | |
| §63.10(d)(5)(i) | Startup, Shutdown, and Malfunction Reports | Yes | Except that reports are not required if actions are consistent with the SSM plan, unless requested by permitting authority. |
| §63.10(d)(5)(ii) | | Yes | Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the plan do not need to be reported within 2 and 7 days of |

| | | | |
|---|---|---|---|
| | | | commencing and completing the action, respectively, but must be included in the next periodic report. |
| §63.10(e)(1)–(2) | Additional CMS Reports | Yes | Except that these requirements apply only to a continuous opacity monitoring system or continuous emission monitoring system if you are subject to the NSPS or elect to comply with the NSPS opacity, CO, or $SO_2$limits. Reports of performance evaluations must be submitted in Notification of Compliance Status. |
| §63.10(e)(3) | Excess Emissions/CMS Performance Reports | No | Subpart UUU specifies the applicable requirements. |
| §63.10(e)(4) | COMS Data Reports | Yes | |
| §63.10(f) | Recordkeeping/Reporting Waiver | Yes | |
| §63.11 | Control Device Requirements | Yes | Applicable to flares. |
| §63.13 | Addresses | Yes | |
| §63.14 | Incorporation by Reference | Yes | |
| §63.15 | Available of Information | Yes | |

[70 FR 6966, Feb. 9, 2005, as amended at 71 FR 20462, Apr. 20, 2006]

**Appendix A to Subpart UUU of Part 63—Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)**

*1.0 Scope and Application.*

1.1 Analytes. The analytes for which this method is applicable include any elements with an atomic number between 11 (sodium) and 92 (uranium), inclusive. Specific analytes for which this method was developed include:

| Analyte | CAS No. | Minimum detectable limit |
|---|---|---|

| | | |
|---|---|---|
| Nickel compounds | 7440–02–0 | <2 % of span. |
| Total chlorides | 16887–00–6 | <2 % of span. |

1.2 Applicability. This method is applicable to the determination of analyte concentrations on catalyst particles. This method is applicable for catalyst particles obtained from the fluid catalytic cracking unit (FCCU) regenerator ( *i.e.* , equilibrium catalyst), from air pollution control systems operated for the FCCU catalyst regenerator vent (FCCU fines), from catalytic reforming units (CRU), and other processes as specified within an applicable regulation. This method is applicable only when specified within the regulation.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from the analytical method.

*2.0 Summary of Method.*

2.1 A representative sample of catalyst particles is collected, prepared, and analyzed for analyte concentration using either energy or wavelength dispersive X-ray flourescent (XRF) spectrometry instrumental analyzers. In both types of XRF spectrometers, the instrument irradiates the sample with high energy (primary) x-rays and the elements in the sample absorb the x-rays and then re-emit secondary (fluorescent) x-rays of characteristic wavelengths for each element present. In energy dispersive XRF spectrometers, all secondary x-rays (of all wavelengths) enter the detector at once. The detector registers an electric current having a height proportional to the photon energy, and these pulses are then separated electronically, using a pulse analyzer. In wavelength dispersive XRF spectrometers, the secondary x-rays are dispersed spatially by crystal diffraction on the basis of wavelength. The crystal and detector are made to synchronously rotate and the detector then receives only one wavelength at a time. The intensity of the x-rays emitted by each element is proportional to its concentration, after correcting for matrix effects. For nickel compounds and total chlorides, the XRF instrument response is expected to be linear to analyte concentration. Performance specifications and test procedures are provided to ensure reliable data.

*3.0 Definitions.*

3.1 Measurement System. The total equipment required for the determination of analyte concentration. The measurement system consists of the following major subsystems:

3.1.1 Sample Preparation. That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or sample preparation prior to introducing the sample into the analyzer.

3.1.2 Analyzer. That portion of the system that senses the analyte to be measured and generates an output proportional to its concentration.

3.1.3 Data Recorder. A digital recorder or personal computer used for recording measurement data from the analyzer output.

3.2 Span. The upper limit of the gas concentration measurement range displayed on the data recorder.

3.3 Calibration Standards. Prepared catalyst samples or other samples of known analyte concentrations used to calibrate the analyzer and to assess calibration drift.

3.4 Energy Calibration Standard. Calibration standard, generally provided by the XRF instrument manufacturer, used for assuring accuracy of the energy scale.

3.5 Accuracy Assessment Standard. Prepared catalyst sample or other sample of known analyte concentrations used to assess analyzer accuracy error.

3.6 Zero Drift. The difference in the measurement system output reading from the initial value for zero concentration level calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.7 Calibration Drift. The difference in the measurement system output reading from the initial value for the mid-range calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.8 Spectral Interferences. Analytical interferences and excessive biases caused by elemental peak overlap, escape peak, and sum peak interferences between elements in the samples.

3.9 Calibration Curve. A graph or other systematic method of establishing the relationship between the analyzer response and the actual analyte concentration introduced to the analyzer.

3.10 Analyzer Accuracy Error. The difference in the measurement system output reading and the ideal value for the accuracy assessment standard.

*4.0 Interferences.*

4.1 Spectral interferences with analyte line intensity determination are accounted for within the method program. No action is required by the XRF operator once these interferences have been addressed within the method.

4.2 The X-ray production efficiency is affected by particle size for the very lightest elements. However, particulate matter (PM) 2.5 particle size effects are substantially < 1 percent for most elements. The calibration standards should be prepared with material of similar particle size or be processed (ground) to produce material of similar particle size as the catalyst samples to be analyzed. No additional correction for particle size is performed. Alternatively, the sample can be fused in order to eliminate any potential particle size effects.

*5.0 Safety.*

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 X-ray Exposure. The XRF uses X-rays; XRF operators should follow instrument manufacturer's guidelines to protect from accidental exposure to X-rays when the instrument is in operation.

5.3 Beryllium Window. In most XRF units, a beryllium (Be) window is present to separate the sample chamber from the X-ray tube and detector. The window is very fragile and brittle. Do not allow sample or debris to fall onto the window, and avoid using compressed air to clean the window because it will cause the window to rupture. If the window should rupture, note that Be metal is poisonous. Use extreme caution when collecting pieces of Be and consult the instrument manufacturer for advice on cleanup of the broken window and replacement.

*6.0 Equipment and Supplies.*

6.1 Measurement System. Use any measurement system that meets the specifications of this method listed in section 13. The typical components of the measurement system are described below.

6.1.1 Sample Mixer/Mill. Stainless steel, or equivalent to grind/mix catalyst and binders, if used, to produce uniform particle samples.

6.1.2 Sample Press/Fluxer. Stainless steel, or equivalent to produce pellets of sufficient size to fill analyzer sample window, or alternatively, a fusion device capable of preparing a fused disk of sufficient size to fill analyzer sample window.

6.1.3 Analytical Balance. ±0.0001 gram accuracy for weighing prepared samples (pellets).

6.1.4 Analyzer. An XRF spectrometer to determine the analyte concentration in the prepared sample. The analyzer must meet the applicable performance specifications in section 13.

6.1.5 Data Recorder. A digital recorder or personal computer for recording measurement data. The data recorder resolution ( *i.e.* , readability) must be 0.5 percent of span. Alternatively, a digital or analog meter having a resolution of 0.5 percent of span may be used to obtain the analyzer responses and the readings may be recorded manually.

*7.0 Reagents and Standards.*

7.1 Calibration Standards. The calibration standards for the analyzer must be prepared catalyst samples or other material of similar particle size and matrix as the catalyst samples to be tested that have known concentrations of the analytes of interest. Preparation (grinding/milling/fusion) of the calibration standards should follow the same processes used to prepare the catalyst samples to be tested. The calibration standards values must be established as the average of a minimum of three analyses using an approved EPA or ASTM method with instrument analyzer calibrations traceable to the U.S. National Institute of Standards and Technology (NIST), if available. The maximum percent deviation of the triplicate calibration standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). If the calibration analyses do not meet this criteria, the calibration standards must be re-analyzed. If unacceptable variability persists, new calibration standards must be prepared. Approved methods for the calibration standard analyses include, but are not limited to, EPA Methods 6010B, 6020, 7520, or 7521 of SW–846.[1] Use a minimum of four calibration standards as specified below (see Figure 1):

7.1.1 High-Range Calibration Standard. Concentration equivalent to 80 to 100 percent of the span. The concentration of the high-range calibration standard should exceed the maximum concentration anticipated in the catalyst samples.

7.1.2 Mid-Range Calibration Standard. Concentration equivalent to 40 to 60 percent of the span.

7.1.3 Low-Range Calibration Standard. Concentration equivalent to 1 to 20 percent of the span. The concentration of the low-range calibration standard should be selected so that it is less than either one-forth of the applicable concentration limit or of the lowest concentration anticipated in the catalyst samples.

7.1.4 Zero Calibration Standard. Concentration of less than 0.25 percent of the span.

7.2 Accuracy Assessment Standard. Prepare an accuracy assessment standard and determine the ideal value for the accuracy assessment standard following the same procedures used to prepare and analyze the calibration standards as described in section 7.1. The maximum percent deviation of the triplicate accuracy assessment standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). The concentration equivalent of the accuracy assessment standard must be between 20 and 80 percent of the span.

7.3 Energy Calibration Standard. Generally, the energy calibration standard will be provided by the XRF instrument manufacturer for energy dispersive spectrometers. Energy calibration is performed using the manufacturer's recommended calibration standard and involves measurement of a specific energy line (based on the metal in the energy calibration standard). This is generally an automated procedure used to assure the accuracy of the energy scale. This calibration standard may not be applicable to all models of XRF spectrometers (particularly wavelength dispersive XRF spectrometers).

*8.0 Sample Collection, Preservation, Transport, and Storage. [Reserved]*

*9.0 Quality Control.*

9.1 Energy Calibration. For energy dispersive spectrometers, conduct the energy calibration by analyzing the energy calibration standard provided by the manufacturer. The energy calibration involves measurement of a specific energy line (based on the metal in the energy calibration standard) and then determination of the difference between the measured peak energy value and the ideal value. This analysis, if applicable, should be performed daily prior to any sample analyses to check the instrument's energy scale. This is generally an automated procedure and assures the accuracy of the energy scale. If the energy scale calibration process is not automated, follow the manufacturer's procedures to manually adjust the instrument, as necessary.

9.2 Zero Drift Test. Conduct the zero drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the zero calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.3 Calibration Drift Test. Conduct the calibration drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the mid-range calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.4 Analyzer Accuracy Test. Conduct the analyzer accuracy test by analyzing the accuracy assessment standard and comparing the value output by the measurement system with the ideal value for the accuracy assessment standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

*10.0 Calibration and Standardization.*

10.1 Perform the initial calibration and set-up following the instrument manufacturer's instructions. These procedures should include, at a minimum, the major steps listed in sections 10.2 and 10.3. Subsequent calibrations are to be performed when either a quality assurance/quality control (QA/QC) limit listed in section 13 is exceeded or when there is a change in the excitation conditions, such as a change in the tube, detector, X-ray filters, or signal processor. Calibrations are typically valid for 6 months to 1 year.

10.2 Instrument Calibration. Calibration is performed initially with calibration standards of similar matrix and binders, if used, as the samples to be analyzed (see Figure 1).

10.3 Reference Peak Spectra. Acquisition of reference spectra is required only during the initial calibration. As long as no processing methods have changed, these peak shape references remain valid. This procedure consists of placing the standards in the instrument and acquiring individual elemental spectra that are stored in the method file with each of the analytical conditions. These reference spectra are used in the standard deconvolution of the unknown spectra.

*11.0 Analytical Procedure.*

11.1 Sample Preparation. Prepare catalyst samples using the same procedure used to prepare the calibration standards. Measure and record the weight of sample used. Measure and record the amount of binder, if any, used. Pellets or films must be of sufficient size to cover the analyzer sample window.

11.2 Sample Analyses. Place the prepared catalyst samples into the analyzer. Follow the manufacturer's instructions for analyzing the samples.

11.3 Record and Store Data. Use a digital recorder or personal computer to record and store results for each sample. Record any mechanical or software problems encountered during the analysis.

*12.0 Data Analysis and Calculations.*

Carry out the following calculations, retaining at least one extra significant figure beyond that of the acquired data. Round off figures after final calculation.

12.1 Drift. Calculate the zero and calibration drift for the tests described in sections 9.2 and 9.3 (see also Figure 2) as follows:

$$\text{QC Value} = \frac{\textit{CurrentAnalyzerCal}.\text{Response} - \text{InitialCal.Response}}{\text{Span}} \times 100 \qquad \text{(Eq. A-1)}$$

Where:

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

InitialCal.Response = Initial instrument response for calibration standard;

QC Value = QC metric (zero drift or calibration drift), percent of span;

Span = Span of the monitoring system.

12.2 Analyzer Accuracy. Calculate the analyzer accuracy error for the tests described in section 9.4 (see also Figure 2) as follows:

$$\text{Accuracy Value} = \frac{\textit{CurrentAnalyzerCal}.\text{Response} - \text{IdealCal.Response}}{\text{IdealCal.Response}} \times 100 \qquad \text{(Eq. A-2)}$$

Where:

Accuracy Value = Percent difference of instrument response to the ideal response for the accuracy assessment standard;

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

IdealCal.Response = Ideal instrument response for the accuracy assessment standard.

*13.0 Method Performance.*

13.1 Analytical Range. The analytical range is determined by the instrument design. For this method, a portion of the analytical range is selected by choosing the span of the monitoring system. The span of the monitoring system must be selected such that it encompasses the range of concentrations anticipated to occur in the catalyst sample. If applicable, the span must be selected such that the analyte concentration equivalent to the emission standard is not less than 30 percent of the span. If the measured analyte concentration exceeds the concentration of the high-range calibration standard, the sample analysis is considered invalid. Additionally, if the measured analyte concentration is less than the concentration of the low-range calibration standard but above the detectable limit, the sample analysis results must be flagged with a footnote stating, in effect, that the analyte was detected but that the reported concentration is below the lower quantitation limit.

13.2 Minimum Detectable Limit. The minimum detectable limit depends on the signal-to-noise ratio of the measurement system. For a well-designed system, the minimum detectable limit should be less than 2 percent of the span.

13.3 Zero Drift. Less than ±2 percent of the span.

13.4 Calibration Drift. Less than ±5 percent of the span.

13.5 Analyzer Accuracy Error. Less than ±10 percent.

*14.0 Pollution Prevention. [Reserved]*

*15.0 Waste Management. [Reserved]*

*16.0 Alternative Procedures. [Reserved]*

*17.0 References.*

1. U.S. Environmental Protection Agency. 1998. Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. EPA Publication No. SW–846, Revision 5 (April 1998). Office of Solid Waste, Washington, DC.

*18.0 Tables, Diagrams, Flowcharts, and Validation Data.*

| **Date:** | | | | | |
|---|---|---|---|---|---|
| **Analytic Method Used:** | | | | | |
| | **Zero[a]** | **Low-Range[b]** | **Mid-Range[c]** | **High-Range[d]** | **Accuracy Std[e]** |
| Sample Run: | | | | | |
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| Average | | | | | |
| Maximum Percent Deviation | | | | | |

[a]Average must be less than 0.25 percent of span.

[b]Average must be 1 to 20 percent of span.

[c]Average must be 40 to 60 percent of span.

[d]Average must be 80 to 100 percent of span.

[e]Average must be 20 to 80 percent of span.

Figure 1. Data Recording Sheet for Analysis of Calibration Samples.

Source Identification:

Run Number:

Test Personnel:

Span:

Date:

| | Initial calibration response | Current analyzer calibration response | Drift (percent of span) |
|---|---|---|---|
| Zero Standard | | | |
| Mid-range Standard | | | |

| | Ideal calibration response | Current analyzer calibration response | Accuracy error (percent of ideal) |
|---|---|---|---|
| Accuracy Standard | | | |

Figure 2. Data Recording Sheet for System Calibration Drift Data.

[70 FR 6970, Feb. 9, 2005]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment C
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984**

**Source:** 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

**§ 60.110b Applicability and designation of affected facility.**

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters ($m^3$ ) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 $m^3$ storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 $m^3$ but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 $m^3$ used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 $m^3$ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 $m^3$ but less than 151 $m^3$ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

## § 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

*Bulk gasoline plant* means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

*Condensate* means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

*Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

*Fill* means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

*Gasoline service station* means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

*Maximum true vapor pressure* means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

*Process tank* means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

*Reid vapor pressure* means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

*Storage vessel* means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

*Volatile organic liquid (VOL)* means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

*Waste* means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

## § 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 $m^3$ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 $m^3$ but less than 151 $m^3$ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 $m^3$ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

## § 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this

section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 $Cm^2$ per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 $cm^2$ per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and

liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

## § 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in theFederal Registera notice permitting the use of the alternative means for purposes of compliance with that requirement.

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

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

## § 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

## § 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 $m^3$ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 $m^3$ but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 $m^3$ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 $m^3$ but less than 151 $m^3$ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

## § 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment D
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**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 emission points that are specified in paragraphs (c)(5) through (c)(7) of this section that are located at a plant site that meet the criteria in paragraphs (a)(1) and (a)(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 §63.654(h)(6)(i).

(c) For the purpose of this subpart, the affected source shall comprise all emission points, in combination, listed in paragraphs (c)(1) through (c)(7) 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; and

(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.

(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 of this subpart. No 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 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.

(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 promulgation of this subpart. This determination shall be reported as specified in §63.654(h)(6)(ii) of this subpart.

(f) The owner or operator 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 promulgation of this subpart. This determination shall be reported as specified in §63.654(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) Except as provided in paragraphs (k), (l), or (m) of this section, sources subject to this subpart are required to achieve compliance on or before the dates specified in paragraphs (h)(1) through (h)(4) of this section.

(1) New sources that commence construction or reconstruction after July 14, 1994 shall be in compliance with this subpart upon initial startup or the date of promulgation of this subpart, whichever is later, as provided in §63.6(b) of subpart A of this part.

(2) Except as provided in paragraphs (h)(3) through (h)(5) of this section, existing sources shall be in compliance with this subpart no later than August 18, 1998, except as provided in §63.6(c) of subpart A of this part, or unless an extension has been granted by the Administrator as provided in §63.6(i) of subpart A of this part.

(3) Marine tank vessels at existing sources shall be in compliance with this subpart no later than August 18, 1999 unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998 unless an extension has been granted by the Administrator as provided in §63.6(i).

(4) Existing Group 1 floating roof storage vessels shall be in compliance with §63.646 at the first degassing and cleaning activity after August 18, 1998, or within 10 years after promulgation of the rule, whichever is first.

(5) 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)(5)(i) through (h)(5)(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 upon initial startup of the reconstructed source or by the date of promulgation of this subpart, 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 90 days after the date of promulgation of this subpart);

(ii) The Notification of Compliance Status report as required by §63.654(f) for a new source, addition, or change;

(iii) Periodic Reports and Other Reports as required by §63.654 (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), and (h)(1) through (h)(3) 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, or marine tank vessel loading operation that meets the criteria in paragraphs (c)(1) through (c)(7) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emission point(s) (as defined in §63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraphs (i) or (j) of this section, the requirements in paragraphs (l)(1) through (l)(3) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph 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 §63.654(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 this subpart by the dates specified in paragraphs (l)(2)(i) or (l)(2)(ii) of this section, as applicable.

(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 3 years after the date of promulgation 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 3 years after the date of promulgation of this subpart, 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, or marine tank vessel loading operation meeting the criteria in paragraphs (c)(1) through (c)(7) 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 (l)(3)(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 (l)(3)(vii) of this section. The applicable reports include, but are not limited to:

(i) The Notification of Compliance Status report as required by §63.654(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.654 (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), and (h)(1) through (h)(3) of subpart R of this part. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §63.567 of subpart Y of this part. 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 requirements of this subpart for existing sources for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

(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 subpart CC with other regulations for storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 1 or Group 2 storage vessel that is part of an existing source and is also 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.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 storage vessel that is part of a new source and is subject to 40 CFR part 60, subpart Kb is required to comply only with 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 the control requirements in §60.112b of 40 CFR part 60, subpart Kb is required to comply only with 40 CFR part 60, subpart Kb except as provided in paragraph (n)(8) of this section.

(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 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.

(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, subparts K or Ka is required to only comply with the provisions of this subpart.

(6) After compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the control requirements of 40 CFR part 60, subparts K or Ka is required to comply only with the provisions of 40 CFR part 60, subparts K or Ka except as provided for in paragraph (n)(9) of this section.

(7) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to 40 CFR part 60, subparts K or Ka, but not to the control requirements of 40 CFR part 60, subparts K or Ka, is required to comply only with this subpart.

(8) Storage vessels described by paragraphs (n)(1) and (n)(3) of this section are to comply with 40 CFR part 60, subpart Kb except as provided for in paragraphs (n)(8)(i) through (n)(8)(vi) 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 subpart Kb or to inspect the vessel to determine compliance with §60.113b(a) of subpart Kb 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 §63.120(b)(7)(ii) of subpart G.

(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).

(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 subpart Ka 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 §63.120(b)(7)(ii) of subpart G.

(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.

(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 (o)(2)(i)(C) 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.

(ii) Comply with paragraphs (o)(2)(ii)(A) and (o)(2)(ii)(B) 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.

(p) Overlap of subpart CC with other regulations for equipment leaks. 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 are required to comply only with the provisions specified in this subpart.

(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.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29878, June 12, 1996; 63 FR 44140, Aug. 18, 1998; 66 FR 28841, May 25, 2001]

## § 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.

*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.

*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.

*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 §63.654(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.

*Delayed coker vent* means a vent that is typically intermittent in nature, and usually occurs only during the initiation of the depressuring cycle of the decoking operation when vapor from the coke drums cannot be sent to the fractionator column for product recovery, but instead is routed to the atmosphere through a closed blowdown system or directly to the atmosphere in an open blowdown system. The emissions from the decoking phases of delayed coker operations, which include coke drum 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, or equipment leak 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.

*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.

*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 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; 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 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.

*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.

*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* means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of §63.180(d) of subpart H 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.

*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 during normal operation of 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 (steam) ejectors, 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;

(2) Relief valve discharges;

(3) Leaks from equipment regulated under §63.648;

(4) Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;

(5) In situ sampling systems (onstream analyzers);

(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) Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking;

(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.

*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.

*Petroleum-based solvents* means mixtures of aliphatic hydrocarbons or mixtures of one and two ring aromatic hydrocarbons.

*Periodically discharged* means discharges that are intermittent and associated with routine operations. Discharges associated with maintenance activities or process upsets are not considered periodically discharged miscellaneous process vents and are therefore not regulated by the petroleum refinery miscellaneous process vent provisions.

*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.

*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.

*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) An internal floating roof meeting the specifications of §63.119(b) of subpart G except for §63.119 (b)(5) and (b)(6);

(2) An external floating roof meeting the specifications of §63.119(c) of subpart G except for §63.119(c)(2);

(3) 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

(4) 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.

(5) For purposes of emissions averaging, these four technologies are considered equivalent.

*Reference control technology for wastewater* means the use of:

(1) Controls specified in §§61.343 through 61.347 of subpart FF of part 61;

(2) A treatment process that achieves the emission reductions specified in table 7 of this subpart for each individual HAP present in the wastewater stream or is a steam stripper that meets the specifications in §63.138(g) of subpart G of this part; and

(3) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices) the organic HAP emissions in the vapor streams vented from treatment processes (including the steam stripper described in paragraph (2) of this definition) managing wastewater.

*Refinery fuel gas* means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

*Relief valve* means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

*Research and development facility* means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

*Shutdown* means the cessation of a petroleum refining process unit or a unit operation (including, but not limited to, a distillation unit or reactor) within a petroleum refining process unit for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair.

*Startup* means the setting into operation of a petroleum refining process unit for purposes of production. Startup does not include operation solely for purposes of testing equipment. Startup does not include changes in product for flexible operation units.

*Storage vessel* means a tank or other vessel that is used to store organic liquids. Storage vessel does not include:

(1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(2) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(3) Vessels with capacities smaller than 40 cubic meters;

(4) Bottoms receiver tanks; or

(5) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

*Temperature monitoring device* means a unit of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

*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.

*Wastewater* means water or wastewater that, during production or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product and is discharged into any individual drain system. Examples are feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29879, June 12, 1996; 62 FR 7938, Feb. 21, 1997; 63 FR 31361, June 9, 1998; 63 FR 44141, Aug. 18, 1998]

## § 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) [Reserved]

(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.

(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) 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 this subpart. 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, floppy disk, magnetic tape, or microfiche.

(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:

$E_A$= Emission rate, megagrams per year, allowed for the source.

$0.02\Sigma\ EPV_1$= Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in §63.641.

$\Sigma\ EPV_2$= Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in §63.641.

$0.05\Sigma\ ES_1$= Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in §63.641.

$\Sigma\ ES_2$= Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in §63.641.

$\Sigma\ EGLR_{1C}$= Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in §63.641.

$\Sigma$ $EGLR_2$= Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in §63.641.

(R)$\Sigma$ $EMV_1$= Sum of the residual emissions megagrams per year, from all Group 1 marine tank vessels, as defined in §63.641.

R = 0.03 for existing sources, 0.02 for new sources.

$\Sigma$ $EMV_2$= Sum of the emissions, megagrams per year from all Group 2 marine tank vessels, as defined in §63.641.

$\Sigma$ $EWW_{1C}$= Sum of the residual emissions from all Group 1 wastewater streams, as defined in §63.641. This term is calculated for each Group 1 stream according to the equation for $EWW_{ic}$in §63.652(h)(6).

$\Sigma$ $EWW_2$= Sum of emissions from all Group 2 wastewater streams, as defined in §63.641.

The emissions level represented by this equation is dependent on the collection of emission points in the source. The level is not fixed and can change as the emissions from each emission point change or as the number of emission points in the source changes.

(h) The owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k) of this section for all other emission points within the source.

(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 miscellaneous process vent provisions in §§63.643 through 63.645, the storage vessel provisions in §63.646, the wastewater provisions in §63.647, the gasoline loading rack provisions in §63.650, and the marine tank vessel loading operation provisions in §63.651 of this subpart.

(1) The owner or operator using this compliance approach shall also comply with the requirements of §63.654 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 63.647, §§63.650 and 63.651 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 (l)(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 §§63.652, 63.653, and 63.654, 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.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29879, June 12, 1996]

## § 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 paragraphs (a)(1) or (a)(2) of this section.

(1) Reduce emissions of organic HAP's using a flare that meets the requirements of §63.11(b) of subpart A of this part.

(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.

## § 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), (a)(2), (a)(3), or (a)(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.

(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, 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.

(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 §63.654(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 shall comply with either paragraph (c)(1) or (c)(2) of this section. Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, pressure relief valves needed for safety reasons, and equipment subject to §63.648 are not subject to this paragraph.

(1) Install, calibrate, maintain, and operate a flow indicator that determines whether a vent stream flow is present at least once every hour. Records shall be generated as specified in §63.654(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 closed 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 closed position and the vent stream is not diverted through the bypass line.

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.654(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 §63.654(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998]

## § 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, as appropriate, shall be used for selection of the sampling site.

(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, or 2D of 40 CFR part 60, appendix A, as appropriate.

(3) Method 18 or Method 25A of 40 CFR part 60, appendix A shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. If Method 25A is used, and the TOC mass flow rate calculated from the Method 25A measurement is greater than or equal to 33 kilograms per day for an existing source or 6.8 kilograms per day for a new source, Method 18 may be used to determine any non-VOC hydrocarbons that may be deducted to calculate the TOC (minus non-VOC hydrocarbons) concentration and mass flow rate. The following procedures shall be used to calculate parts per million by volume concentration:

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) The TOC concentration ($C_{TOC}$) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation if Method 18 is used:

$$C_{TOC} = \frac{\sum_{i=1}^{x}\left(\sum_{j=1}^{n} C_{ji}\right)}{X}$$

where:

$C_{TOC}$=Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

$C_{ji}$=Concentration of sample component j of the sample i, dry basis, parts per million by volume.

n=Number of components in the sample.

x=Number of samples in the sample run.

(4) The emission rate of TOC (minus methane and ethane) ($E_{TOC}$) shall be calculated using the following equation if Method 18 is used:

$$E = K_2 \left[ \sum_{j=1}^{n} C_j M_j \right] Q_s$$

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.

$C_j$=Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section. $C_j$includes all organic compounds measured minus methane and ethane.

$M_j$=Molecular weight of organic compound j, gram per gram-mole.

$Q_s$=Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(5) If Method 25A is used, the emission rate of TOC ($E_{TOC}$) shall be calculated using the following equation: –

$E_{TOC}=K_2C_{TOC}MQ_s$

where:

$E_{TOC}$=Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

$K_2$=Constant, $5.986\times10^{-5}$(parts per million)$^{-1}$(gram-mole per standard cubic meter) (kilogram per gram)(minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

$C_{TOC}$=Concentration of TOC on a dry basis in parts per million volume as measured by Method 25A of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section.

M=Molecular weight of organic compound used to express units of $C_{TOC}$, gram per gram-mole.

$Q_s$=Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(g) Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate.

(1) Engineering assessment includes, but is not limited to, the following:

(i) Previous test results provided the tests are representative of current operating practices at the process unit.

(ii) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(iii) TOC emission rate specified or implied within a permit limit applicable to the process vent.

(iv) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(A) Use of material balances based on process stoichiometry to estimate maximum TOC concentrations;

(B) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities; and

(C) Estimation of TOC concentrations based on saturation conditions.

(v) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(h) The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based.

(1) The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in paragraphs (e) and (f) of this section, as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in paragraph (g) of this section.

(2) Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.654 (f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640.

(i) A compliance determination for visible emissions shall be conducted within 150 days of the compliance date using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998]

## § 63.646 Storage vessel provisions.

(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 judgement 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, Method 18 of 40 CFR part 60, appendix A shall be used.

(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) shall be replaced with §63.654(f).

(k) References to the Periodic Reports in §63.152(c) shall be replaced with §63.654(g).

(l) The State or local permitting authority can waive the notification requirements of §§63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §§63.120(a)(6) or 63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 62 FR 7939, Feb. 21, 1997]

## § 63.647 Wastewater provisions.

(a) Except as provided in paragraph (b) 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 40 CFR part 61, subpart FF 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) 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), (a)(2), and (c) through (i) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) 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.

(b) The use of monitoring data generated before August 18, 1995 to qualify for less frequent monitoring of valves and pumps as provided under 40 CFR part 60 subpart VV or subpart H of this part and paragraph (c) of this section (i.e., quarterly or semiannually) is governed by the requirements of paragraphs (b)(1) and (b)(2) of this section.

(1) Monitoring data must meet the test methods and procedures specified in §60.485(b) of 40 CFR part 60, subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part except for minor departures.

(2) Departures from the criteria specified in §60.485(b) of 40 CFR part 60 subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part or from the monitoring frequency specified in subpart VV or in paragraph (c) of this section (such as every 6 weeks instead of monthly or quarterly) are minor and do not significantly affect the quality of the data. An example of a minor departure is monitoring at a slightly different frequency (such as every 6 weeks instead of monthly or quarterly). Failure to use a calibrated instrument is not considered a minor departure.

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H of this part except as provided in paragraphs (c)(1) through (c)(10) and (e) through (i) of this section.

(1) The instrument readings that define a leak for light liquid pumps subject to §63.163 of subpart H of this part and gas/vapor and light liquid valves subject to §63.168 of subpart H of this part are specified in table 2 of this subpart.

(2) In phase III of the valve standard, the owner or operator may monitor valves for leaks as specified in paragraphs (c)(2)(i) or (c)(2)(ii) of this section.

(i) If the owner or operator does not elect to monitor connectors, then the owner or operator shall monitor valves according to the frequency specified in table 8 of this subpart.

(ii) If an owner or operator elects to monitor connectors according to the provisions of §63.649, paragraphs (b), (c), or (d), then the owner or operator shall monitor valves at the frequencies specified in table 9 of this subpart.

(3) The owner or operator shall decide no later than the first required monitoring period after the phase I compliance date specified in §63.640(h) whether to calculate the percentage leaking valves on a process unit basis or on a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(4) The owner or operator shall decide no later than the first monitoring period after the phase III compliance date specified in §63.640(h) whether to monitor connectors according to the provisions in §63.649, paragraphs (b), (c), or (d).

(5) Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in §63.169 of subpart H of this part (except for the agitator provisions). The leak definition for valves, connectors, and instrumentation systems subject to §63.169 is 1,000 parts per million.

(6) In phase III of the pump standard, except as provided in paragraph (c)(7) of this section, owners or operators that achieve less than 10 percent of light liquid pumps leaking or three light liquid pumps leaking, whichever is greater, shall monitor light liquid pumps monthly.

(7) Owners or operators that achieve less than 3 percent of light liquid pumps leaking or one light liquid pump leaking, whichever is greater, shall monitor light liquid pumps quarterly.

(8) An owner or operator may make the election described in paragraphs (c)(3) and (c)(4) of this section at any time except that any election to change after the initial election shall be treated as a permit modification according to the terms of part 70 of this chapter.

(9) When complying with the requirements of §63.168(e)(3)(i), non-repairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and non-repairable. Otherwise, a number of non-repairable valves up to a maximum of 1 percent per year of the total number of valves in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percent leaking valves for subsequent monitoring periods. When the number of non-repairable valves exceeds 3

percent of the total number of valves in organic HAP service, the number of non-repairable valves exceeding 3 percent of the total number shall be included in the calculation of percent leaking valves.

(10) If in phase III of the valve standard any valve is designated as being leakless, the owner or operator has the option of following the provisions of 40 CFR 60.482–7(f). If an owner or operator chooses to comply with the provisions of 40 CFR 60.482–7(f), the valve is exempt from the valve monitoring provisions of §63.168 of subpart H of this part.

(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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998]

### § 63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(a) If an owner or operator elects to monitor valves according to the provisions of §63.648(c)(2)(ii), the owner or operator shall implement one of the connector monitoring programs specified in paragraphs (b), (c), or (d) of this section.

(b) *Random 200 connector alternative.* The owner or operator shall implement a random sampling program for accessible connectors of 2.0 inches nominal diameter or greater. The program does not apply to inaccessible or unsafe-to-monitor connectors, as defined in §63.174 of subpart H. The sampling program shall be implemented source-wide.

(1) Within the first 12 months after the phase III compliance date specified in §63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.

(2) The instrument reading that defines a leak is 1,000 parts per million.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.

(5) After conducting the initial survey required in paragraph (b)(1) of this section, the owner or operator shall conduct subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall survey a random sample of 200 connectors once every 6 months.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall survey a random sample of 200 connectors once per year.

(iii) If the percentage leaking connectors is 0.5 percent or greater but less than 1.0 percent, the owner or operator shall survey a random sample of 200 connectors once every 2 years.

(iv) If the percentage leaking connectors is less than 0.5 percent, the owner or operator shall survey a random sample of 200 connectors once every 4 years.

(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(c) *Connector inspection alternative.* The owner or operator shall implement a program to monitor all accessible connectors in gas/vapor service that are 2.0 inches (nominal diameter) or greater and inspect all accessible connectors in light liquid service that are 2 inches (nominal diameter) or greater as described in paragraphs (c)(1) through (c)(7) of this section. The program does not apply to inaccessible or unsafe-to-monitor connectors.

(1) Within 12 months after the phase III compliance date specified in §63.640(h), all connectors in gas/vapor service shall be monitored using Method 21 of 40 CFR part 60 appendix A. The instrument reading that defines a leak is 1,000 parts per million.

(2) All connectors in light liquid service shall be inspected for leaks. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(3) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected except as provided in paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, connectors in gas/vapor service shall be monitored for leaks within the first 3 months after repair. Connectors in light liquid service shall be inspected for indications of leaks within the first 3 months after repair. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(5) After conducting the initial survey required in paragraphs (c)(1) and (c)(2) of this section, the owner or operator shall conduct subsequent monitoring at the frequencies specified in paragraphs (c)(5)(i) through (c)(5)(iii) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall monitor or inspect, as applicable, the connectors once per year.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 2 years.

(iii) If the percentage leaking connectors is less than 1.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 4 years.

(6) The percentage leaking connectors shall be calculated for connectors in gas/vapor service and for connectors in light liquid service. The data for the two groups of connectors shall not be pooled for the purpose of determining the percentage leaking connectors.

(i) The percentage leaking connectors shall be calculated as follows:

$$\% C_L=[(C_L-C_{AN})/C_t+C_c)]\times 100$$

where:

$\% C_L$=Percentage leaking connectors.

$C_L$=Number of connectors including nonrepairables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, Appendix A.

$C_{AN}$=Number of allowable nonrepairable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, $C_t$.

$C_t$=Total number of monitored connectors, including nonrepairables, in the process unit.

$C_c$=Optional credit for removed connectors=0.67×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)(4)(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 (c) of this section, 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, §§63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3).

(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).

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996]

## § 63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (d) 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 63.567.

(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 Initial Notification Report under §63.567(b) is 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)(3).

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996]

## § 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 63.647, and §§63.650 and 63.651. Existing marine tank vessel loading operations unable to comply with the standard by using emissions averaging are those marine tank vessels subject to 40 CFR 63.562(e) of this part and the Valdez Marine Terminal source.

(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 §63.654(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by §63.654(g)(8)(iii).

(f) Debits and credits shall be calculated in accordance with the methods and procedures specified in paragraphs (g) and (h) of this section, respectively, and shall not include emissions from the following:

(1) More than 20 individual emission points. Where pollution prevention measures (as specified in paragraph (j)(1) of this section) are used to control emission points to be included in an emissions average, no more than 25 emission points may be included in the average. For example, if two emission points to be included in an emissions average are controlled by pollution prevention measures, the average may include up to 22 emission points.

(2) Periods of startup, shutdown, and malfunction as described in the source's startup, shutdown, and malfunction plan required by §63.6(e)(3) of subpart A of this part.

(3) For emission points for which continuous monitors are used, periods of excess emissions as defined in §63.654(g)(6)(i). For these periods, the calculation of monthly credits and debits shall be adjusted as specified in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) No credits would be assigned to the credit-generating emission point.

(ii) Maximum debits would be assigned to the debit-generating emission point.

(iii) The owner or operator may use the procedures in paragraph (l) of this section to demonstrate to the Administrator that full or partial credits or debits should be assigned.

(g) Debits are generated by the difference between the actual emissions from a Group 1 emission point that is uncontrolled or is controlled to a level less stringent than the reference control technology, and the emissions allowed for Group 1 emission point. Debits shall be calculated as follows:

(1) The overall equation for calculating sourcewide debits is:

$$Debits = \sum_{i=1}^{n}\left(EPV_{iACTUAL} - (0.02)\,EPV_{iu}\right) + \sum_{i=1}^{n}\left(ES_{iACTUAL} - (0.05)\,ES_{iu}\right) + \sum_{i=1}^{n}\left(EGLR_{iACTUAL} - EGLR_{iC}\right) + \sum_{i=1}^{n}\left(EMV_{iACTUAL} - (0.03)\,EMViu\right)$$

where:

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

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

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

$ES_{iACTUAL}$=Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.

(0.05) $ES_{iu}$=Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.

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

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

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

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

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

(2) Emissions from miscellaneous process vents shall be calculated as follows:

(i) For purposes of determining miscellaneous process vent stream flow rate, organic HAP concentrations, and temperature, the sampling site shall be after the final product recovery device, if any recovery devices are present; before any control device (for miscellaneous process vents, recovery devices shall not be considered control devices); and before discharge to the atmosphere. Method 1 or 1A of part 60, appendix A shall be used for selection of the sampling site.

(ii) The following equation shall be used for each miscellaneous process vent i to calculate $EPV_{iu}$:

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

where:

$EPV_{iu}$=Uncontrolled process vent emission rate from miscellaneous process vent i, megagrams per month.

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

h=Monthly hours of operation during which positive flow is present in the vent, hours per month.

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

$M_j$=Molecular weight of organic HAP j, gram per gram-mole.

n=Number of organic HAP's in the miscellaneous process vent stream.

(A) The values of Q, $C_j$, and $M_j$shall be determined during a performance test conducted under representative operating conditions. The values of Q, $C_j$, and $M_j$shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

(B) If there is a change in capacity utilization other than a change in monthly operating hours, or if any other change is made to the process or product recovery equipment or operation such that the previously measured values of Q, $C_j$, and $M_j$are no longer representative, a new performance test shall be conducted to determine new representative values of Q, $C_j$, and $M_j$. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following procedures and equations shall be used to calculate $EPV_{iACTUAL}$:

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

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

( *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 a boiler or process heater meeting the criteria in §63.645(d) of this subpart 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 $EPV_{iACTUAL}$. 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:

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

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

$$G = \sum_{1}^{j=n} G_j$$

$G_j$=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:

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

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:

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

$T_j$=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 $EGLR_{ic}$:

$$EGLR_{ic} = 1\times10^{-8}\,G$$

G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate $EGLR_{iACTUAL}$:

(A) If the gasoline loading rack is not controlled, $EGLR_{iACTUAL}$=$EGLR_{iu}$, where $EGLR_{iu}$is calculated using the equations specified in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack is controlled using a control device or a pollution prevention measure not achieving the requirement of less than 10 milligrams of TOC per liter of gasoline loaded,

$$EGLR_{iACTUAL} = EGLR_{iu}\left(\frac{1 - Percent\ reduction}{100\%}\right)$$

( *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 $EMV_{iu}$:

$$EMV_{iu} = \sum_{i=1}^{m}(Q_i)(F_i)(P_i)$$

where:

$EMV_{iu}$=Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i, megagrams per month.

$Q_i$=Quantity of commodity loaded (per vessel type), liters.

$F_i$=Emission factor, megagrams per liter.

$P_i$=Percent HAP.

m=Number of combinations of commodities and vessel types loaded.

Emission factors shall be based on test data or emission estimation procedures specified in §63.565(l) of subpart Y.

(ii) The following procedures and equations shall be used to calculate $EMV_{iACTUAL}$:

(A) If the marine tank vessel is not controlled, $EMV_{iACTUAL}=EMV_{iu}$, where $EMV_{iu}$is calculated using the equations specified in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel is controlled using a control device or a pollution prevention measure achieving less than 97-percent reduction,

$$EMV_{iACTUAL} = EMV_{iu}\left(\frac{1 - Percent\ reduction}{100\%}\right)$$

( *1* ) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.565(c) of subpart Y. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

( *2* ) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(h) Credits are generated by the difference between emissions that are allowed for each Group 1 and Group 2 emission point and the actual emissions from a Group 1 or Group 2 emission point that has been controlled after November 15, 1990 to a level more stringent than what is required by this subpart or any other State or Federal rule or statute. Credits shall be calculated as follows:

(1) The overall equation for calculating sourcewide credits is:

$$\begin{aligned} Credits = {} & D\sum_{i=1}^{n}\left((0.02)\ \mathrm{EPV1}_{iu} - EPV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EPV2_{iBASE} - EPV2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left((0.05)\ \mathrm{ES1}_{iu} - ES1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(ES2_{iBASE} - ES2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left(\mathrm{EGLR}_{ic} - EGLRl_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EGLR2_{iBASE} - EGLR2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left((0.03)\ \mathrm{EMV1}_{iu} - EMV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EMV2_{iBASE} - EMV2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left(\mathrm{EWW1}_{ic} - EWW1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EWW2_{iBASE} - EWW2_{iACTUAL}\right) \end{aligned}$$

where:

Credits and all terms of the equation are in units of megagrams per month, the baseline date is November 15, 1990, and

D=Discount factor=0.9 for all credit-generating emission points except those controlled by a pollution prevention measure, which will not be discounted.

$EPV1_{iACTUAL}$=Emissions for each Group 1 miscellaneous process vent i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

(0.02) $EPV1_{iu}$=Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions. $EPV1_{iu}$is calculated according to paragraph (h)(2) of this section.

$EPV2_{iBASE}$=Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

$EPV2_{iACTUAL}$=Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

$ES1_{iACTUAL}$=Emissions from each Group 1 storage vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

(0.05) $ES1_{iu}$=Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions. $ES1_{iu}$is calculated according to paragraph (h)(3) of this section.

$ES2_{iACTUAL}$=Emissions from each Group 2 storage vessel i that is controlled, calculated according to paragraph (h)(3) of this section.

$ES2_{iBASE}$=Emissions from each Group 2 storage vessel i at the baseline date, as calculated in paragraph (h)(3) of this section.

$EGLR1_{iACTUAL}$=Emissions from each Group 1 gasoline loading rack i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

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

$EGRL2_{iACTUAL}$=Emissions from each Group 2 gasoline loading rack i that is controlled, calculated according to paragraph (h)(4) of this section.

$EGLR2_{iBASE}$=Emissions from each Group 2 gasoline loading rack i at the baseline date, as calculated in paragraph (h)(4) of this section.

$EMV1_{iACTUAL}$=Emissions from each Group 1 marine tank vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

(0.03)$EMV1_{iu}$=Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions. $EMV1_{iu}$is calculated according to paragraph (h)(5) of this section.

$EMV2_{iACTUAL}$=Emissions from each Group 2 marine tank vessel i that is controlled, calculated according to paragraph (h)(5) of this section.

$EMV2_{iBASE}$=Emissions from each Group 2 marine tank vessel i at the baseline date, as calculated in paragraph (h)(5) of this section.

$EWW1_{iACTUAL}$=Emissions from each Group 1 wastewater stream i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.

$EWW1_{ic}$=Emissions from each Group 1 wastewater stream i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.

$EWW2_{iACTUAL}$=Emissions from each Group 2 wastewater stream i that is controlled, calculated according to paragraph (h)(6) of this section.

$EWW2_{iBASE}$=Emissions from each Group 2 wastewater stream i at the baseline date, calculated according to paragraph (h)(6) of this section.

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

m=Number of Group 2 emission points included in the emissions average. The value of m is not necessarily the same for each kind of emission point.

(i) For an emission point controlled using a reference control technology, the percentage of reduction for calculating credits shall be no greater than the nominal efficiency associated with the reference control technology, unless a higher nominal efficiency is assigned as specified in paragraph (h)(1)(ii) of this section.

(ii) For an emission point controlled to a level more stringent than the reference control technology, the nominal efficiency for calculating credits shall be assigned as described in paragraph (i) of this section. A reference control technology may be approved for use in a different manner and assigned a higher nominal efficiency according to the procedures in paragraph (i) of this section.

(iii) For an emission point controlled using a pollution prevention measure, the nominal efficiency for calculating credits shall be determined as described in paragraph (j) of this section.

(2) Emissions from process vents shall be determined as follows:

(i) Uncontrolled emissions from miscellaneous process vents, $EPV1_{iu}$, shall be calculated according to the procedures and equation for $EPV_{iu}$in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(ii) Actual emissions from miscellaneous process vents controlled using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than 98 percent emission reduction, $EPV1_{iACTUAL}$, shall be calculated according to the following equation:

$$EPV1_{iACTUAL} = EPV1_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, $EPV2_{iACTUAL}$:

(A) For a Group 2 process vent controlled by a control device, a recovery device applied as a pollution prevention project, or a pollution prevention measure, if the control achieves a percentage of reduction less than or equal to a 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \times \left(1 - \frac{Percent\ reduction}{100\%}\right)$$

( *1* ) $EPV2_{iu}$shall be calculated according to the equations and procedures for $EPV_{iu}$in paragraphs (g)(2)(i) and (g)(2)(ii) of this section except as provided in paragraph (h)(2)(iii)(A)( *3* ) of this section.

( *2* ) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(2)(iii)(B)( *1* ) through (g)(2)(iii)(B)( *3* ) of this section except as provided in paragraph (h)(2)(iii)(A)( *4* ) of this section.

( *3* ) If a recovery device was added as part of a pollution prevention project, $EPV2_{iu}$shall be calculated prior to that recovery device. The equation for $EPV_{iu}$in paragraph (g)(2)(ii) of this section shall be used to calculate $EPV2_{iu}$; however, the sampling site for measurement of vent stream flow rate and organic HAP concentration shall be at the inlet of the recovery device.

( *4* ) If a recovery device was added as part of a pollution prevention project, the percentage of reduction shall be demonstrated by conducting a performance test at the inlet and outlet of that recovery device.

(B) For a Group 2 process vent controlled using a technology with an approved nominal efficiency greater than a 98 percent or a pollution prevention measure achieving greater than 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iv) Emissions from Group 2 process vents at baseline, $EPV2_{iBASE}$, shall be calculated as follows:

(A) If the process vent was uncontrolled on November 15, 1990, $EPV2_{iBASE}$=$EPV2_{iu}$, and shall be calculated according to the procedures and equation for $EPV_{iu}$in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

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

$$EPV2_{BASE} = EPV2_{iu}\left(1 - \frac{Percent\ reduction\ \%}{100\%}\right)$$

where $EPV2_{iu}$is calculated according to the procedures and equation for $EPV_{iu}$in paragraphs (g)(2)(i) and (g)(2)(ii) of this section. The percentage of reduction shall be calculated according to the procedures specified in paragraphs (g)(2)(iii)(B)( *1* ) through (g)(2)(iii)(B)( *3* ) of this section.

(C) If a recovery device was added to a process vent as part of a pollution prevention project initiated after November 15, 1990, $EPV2_{iBASE}$=$EPV2_{iu}$, where $EPV2_{iu}$is calculated according to paragraph (h)(2)(iii)(A)( *3* ) of this section.

(3) Emissions from storage vessels shall be determined as specified in §63.150(h)(3) of subpart G, except as follows:

(i) All references to §63.119(b) in §63.150(h)(3) of subpart G shall be replaced with: §63.119 (b) or §63.119(b) except for §63.119(b)(5) and (b)(6).

(ii) All references to §63.119(c) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(c) or §63.119(c) except for §63.119(c)(2).

(iii) All references to §63.119(d) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(d) or §63.119(d) except for §63.119(d)(2).

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

(i) Uncontrolled emissions from Group 1 gasoline loading racks, $EGLR1_{iu}$, shall be calculated according to the procedures and equations for $EGLR_{iu}$as described in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(ii) Emissions from Group 1 gasoline loading racks if the reference control technology had been applied, $EGLR_{ic}$, shall be calculated according to the procedures and equations in paragraph (g)(4)(v) of this section.

(iii) Actual emissions from Group 1 gasoline loading racks controlled to less than 10 milligrams of TOC per liter of gasoline loaded; $EGLR_{iACTUAL}$, shall be calculated according to the following equation:

$$EGLR1_{iACTUAL} = EGLR1_{iu}\left(1 - \frac{Nominal\ efficiency}{100\%}\right)$$

(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $EGLR2_{iACTUAL}$:

(A) For a Group 2 gasoline loading rack controlled by a control device or a pollution prevention measure achieving emissions reduction but where emissions are greater than the 10 milligrams of TOC per liter of gasoline loaded requirement,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1 - \frac{Percent\ \text{reduction}}{100\%}\right)$$

( *1* ) $EGLR2_{iu}$shall be calculated according to the equations and procedures for $EGLR_{iu}$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,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1 - \frac{\text{Nominal efficiency}}{100\%}\right)$$

(v) Emissions from Group 2 gasoline loading racks at baseline, $EGLR2_{iBASE}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $EGLR2_{iBASE}=EGLR2_{iu}$, and shall be calculated according to the procedures and equations for $EGLR_{iu}$in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

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

$$EGLR2_{iBASE} = EGLR2_{iu}\left(1-\frac{Percent\ \text{reduction}}{100\%}\right)$$

where $EGLR2_{iu}$is calculated according to the procedures and equations for $EGLR_{iu}$in paragraphs (g)(4)(i) through (g)(4)(iv) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)( *1* ) and (g)(4)(vi)(B)( *2* ) of this section.

(5) Emissions from marine tank vessels shall be determined as follows:

(i) Uncontrolled emissions from Group 1 marine tank vessels, $EMV1_{iu}$, shall be calculated according to the procedures and equations for $EMV_{iu}$as described in paragraph (g)(5)(i) of this section.

(ii) Actual emissions from Group 1 marine tank vessels controlled using a technology or pollution prevention measure with an approved nominal efficiency greater than 97 percent, $EMV_{iACTUAL}$, shall be calculated according to the following equation:

$$EMV1_{iACTUAL} = EMV1_{iu}\left(1-\frac{\text{Nominal efficiency}}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 marine tank vessels, $EMV2_{iACTUAL}$:

(A) For a Group 2 marine tank vessel controlled by a control device or a pollution prevention measure achieving a percentage of reduction less than or equal to 97 percent reduction,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1-\frac{Percent\ \text{reduction}}{100\%}\right)$$

( *1* ) $EMV2_{iu}$shall be calculated according to the equations and procedures for $EMV_{iu}$in paragraph (g)(5)(i) of this section.

( *2* ) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)( *1* ) and (g)(5)(ii)(B)( *2* ) of this section.

(B) For a Group 2 marine tank vessel controlled using a technology or a pollution prevention measure with an approved nominal efficiency greater than 97 percent,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1-\frac{\text{Nominal efficiency}}{100\%}\right)$$

(iv) Emissions from Group 2 marine tank vessels at baseline, $EMV2_{iBASE}$, shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, $EMV2_{iBASE}$equals $EMV2_{iu}$, and shall be calculated according to the procedures and equations for $EMV_{iu}$in paragraph (g)(5)(i) of this section.

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

$$EMV2_{iBASE} = EMV2_{iu}\left(1 - \frac{Percent\ \text{reduction}}{100\%}\right)$$

where $EMV2_{iu}$is calculated according to the procedures and equations for $EMV_{iu}$in paragraph (g)(5)(i) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)( *1* ) and (g)(5)(ii)(B)( *2* ) of this section.

(6) Emissions from wastewater shall be determined as follows:

(i) For purposes of paragraphs (h)(4)(ii) through (h)(4)(vi) of this section, the following terms will have the meaning given them in paragraphs (h)(6)(i)(A) through (h)(6)(i)(C) of this section.

(A) *Correctly suppressed* means that a wastewater stream is being managed according to the requirements of §§61.343 through 61.347 or §61.342(c)(l)(iii) of 40 CFR part 61, subpart FF, as applicable, and the emissions from the waste management units subject to those requirements are routed to a control device that reduces HAP emissions by 95 percent or greater.

(B) *Treatment process* has the meaning given in §61.341 of 40 CFR part 61, subpart FF except that it does not include biological treatment units.

(C) *Vapor control device* means the control device that receives emissions vented from a treatment process or treatment processes.

(ii) The following equation shall be used for each wastewater stream i to calculate $EWW_{ic}$:

$$EWW_{ic} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left(1 - Fr_m\right) Fe_m HAP_{im} + \left(0.05\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left(Fr_m HAP_{im}\right)$$

where:

$EWW_{ic}$= Monthly wastewater stream emission rate if wastewater stream i were controlled by the reference control technology, megagrams per month.

$Q_i$= Average flow rate for wastewater stream i, liters per minute.

$H_i$= Number of hours during the month that wastewater stream i was generated, hours per month.

$Fr_m$=Fraction removed of organic HAP m in wastewater, from table 7 of this subpart, dimensionless.

$Fe_m$=Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

s=Total number of organic HAP's in wastewater stream i.

$HAP_{im}$=Average concentration of organic HAP m in wastewater stream i, parts per million by weight.

(A) $HAP_{im}$shall be determined for the point of generation or at a location downstream of the point of generation. Wastewater samples shall be collected using the sampling procedures specified in Method 25D of 40 CFR part 60, appendix A. Where feasible, samples shall be taken from an enclosed pipe prior to the wastewater being exposed to the atmosphere. When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of organic HAP's prior to sampling. The samples collected may be analyzed by either of the following procedures:

( *1* ) A test method or results from a test method that measures organic HAP concentrations in the wastewater, and that has been validated pursuant to section 5.1 or 5.3 of Method 301 of appendix A of this part may be used; or

( *2* ) Method 305 of appendix A of this part may be used to determine $C_{im}$, the average volatile organic HAP concentration of organic HAP m in wastewater stream i, and then $HAP_{im}$may be calculated using the following equation: $HAP_{im}=C_{im}/Fm_m$, where $Fm_m$for organic HAP m is obtained from table 7 of this subpart.

(B) Values for $Q_i$, $HAP_{im}$, and $C_{im}$shall be determined during a performance test conducted under representative conditions. The average value obtained from three test runs shall be used. The values of $Q_i$, $HAP_{im}$, and $C_{im}$shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (h)(6)(i)(C) of this section.

(C) If there is a change to the process or operation such that the previously measured values of $Q_i$, $HAP_{im}$, and $C_{im}$are no longer representative, a new performance test shall be conducted to determine new representative values of $Q_i$, $HAP_{im}$, and $C_{im}$. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following equations shall be used to calculate $EWW1_{iACTUAL}$for each Group 1 wastewater stream i that is correctly suppressed and is treated to a level more stringent than the reference control technology.

(A) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, and the vapor control device achieves a percentage of reduction equal to 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{5} \left[ Fe_m HAP_{im} \left(1 - PR_{im}\right)\right] + 0.05\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{5} \left[ HAP_{im}\, PR_{im}\right]$$

Where:

$EWW_{iACTUAL}$=Monthly wastewater stream emission rate if wastewater stream i is treated to a level more stringent than the reference control technology, megagrams per month.

$PR_{im}$=The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless, as calculated by:

$$PR_{im} = \frac{HAP_{im\text{-}in} - HAP_{im\text{-}out}}{HAP_{im\text{-}in}}$$

Where:

HAPim-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.

HAPim-out=Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater exiting the last treatment process in the series.

All other terms are as defined and determined in paragraph (h)(6)(ii) of this section.

(B) If the Group 1 wastewater stream i is not controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, but the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{5} \left[Fe_m HAP_{im}\left(1-A_m\right)\right] + \left(1-\frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{5} [$$

Where:

Nominal efficiency=Approved reduction efficiency of the vapor control device, dimensionless, as determined according to the procedures in §63.652(i).

$A_m$=The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless.

All other terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

( *1* ) If a steam stripper meeting the specifications in the definition of reference control technology for wastewater is used, $A_m$shall be equal to the value of $Fr_m$given in table 7 of this subpart.

( *2* ) If an alternative control device is used, the percentage of reduction must be determined using the equation and methods specified in paragraph (h)(6)(iii)(A) of this section for determining $PR_{im}$. If the value of $PR_{im}$is greater than or equal to the value of $Fr_m$given in table 7 of this subpart, then $A_m$equals $Fr_m$unless a higher nominal efficiency has been approved. If a higher nominal efficiency has been approved for the treatment process, the owner or operator shall determine $EWW1_{iACTUAL}$according to paragraph (h)(6)(iii)(B) of this section rather than paragraph (h)(6)(iii)(A) of this section. If $PR_{im}$is less than the value of $FR_m$given in table 7 of this subpart, emissions averaging shall not be used for this emission point.

(C) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated hazardous air pollutant that is greater than that specified in table 7 of this subpart, and the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{5} \left[Fe_m HAP_{im}\left(1-PR_{im}\right)\right] + \left(1-\frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{5}$$

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 $EWW2_{iBASE}$for each Group 2 wastewater stream i that on November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

$$EWW2_{iBASE} = \left(6.0 \times 10^{-8}\right) Q_i \, H_i \sum_{m=1}^{s} Fe_m HAP_{im}$$

Where:

$EWW2_{iBASE}$=Monthly wastewater stream emission rate if wastewater stream i is not correctly suppressed, megagrams per month.

$Q_i$, $H_i$, s, $Fe_m$, and $HAP_{im}$are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(v) The following equation shall be used to calculate $EWW2_{iBASE}$for each Group 2 wastewater stream i on November 15, 1990 was correctly suppressed. $EWW2_{iBASE}$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.

$$EWW2_{iBASE} = \left(6.0 * 10^{-8}\right) Q_i \, H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im} \left(1 - PR_{im}\right)\right] + \left(1 - \frac{R_i}{100\%}\right) \left(6.0 * 10^{-8}\right) Q_i \, H_i \sum_{m=1}^{s} \left[HAP_{im} PR_{im}\right]$$

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, $EWW2_{iACTUAL}$shall be calculated according to the equation for $EWW2_{iBASE}$in paragraph (h)(6)(v) of this section. $EWW2_{iACTUAL}$shall be calculated with all control methods in place accounted for.

(vii) The reduction efficiency, $R_i$, of the vapor control device shall be demonstrated according to the following procedures:

(A) Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate.

(B) The mass flow rate of organic compounds entering and exiting the control device shall be determined as follows:

( *1* ) The time period for the test shall not be less than 3 hours during which at least three runs are conducted.

( *2* ) A run shall consist of a 1-hour period during the test. For each run:

( *i* ) The volume exhausted shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60 appendix A, as appropriate;

( *ii* ) The organic concentration in the vent stream entering and exiting the control device shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

( *3* ) The mass flow rate of organic compounds entering and exiting the control device during each run shall be calculated as follows:

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

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

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.

$C_{aip}$= Concentration of organic compound i measured in the vent stream exiting the control device during run p as determined by Method 18 of 40 CFR part 60 appendix A, parts per million by volume on a dry basis.

$C_{bip}$= Concentration of organic compound i measured in the vent stream entering the control device during run p as determined by Method 18 of 40 CFR part 60, appendix A, parts per million by volume on a dry basis.

$MW_i$= Molecular weight of organic compound i in the vent stream, kilograms per kilogram-mole.

n = Number of organic compounds in the vent stream.

0.0416 = Conversion factor for molar volume, kilograms-mole per cubic meter at 293 kelvin and 760 millimeters mercury absolute.

(C) The organic reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Total organic reduction efficiency for the control device, percentage.

$E_b$= Mass flow rate of organic compounds entering the control device, kilograms per hour.

$E_a$= Mass flow rate of organic compounds exiting the control device, kilograms per hour.

(i) The following procedures shall be followed to establish nominal efficiencies. The procedures in paragraphs (i)(1) through (i)(6) of this section shall be followed for control technologies that are different in use or design from the reference control technologies and achieve greater percentages of reduction than the percentages of efficiency assigned to the reference control technologies in §63.641.

(1) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology, and the different control technology will be used in more than three applications at a single plant site, the owner or operator shall submit the information specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section to the Administrator in writing:

(i) Emission stream characteristics of each emission point to which the control technology is or will be applied including the kind of emission point, flow, organic HAP concentration, and all other stream characteristics necessary to design the control technology or determine its performance;

(ii) Description of the control technology including design specifications;

(iii) Documentation demonstrating to the Administrator's satisfaction the control efficiency of the control technology. This may include performance test data collected using an appropriate EPA method or any other method validated according to Method 301 of appendix A of this part. If it is infeasible to obtain test data, documentation may include a design evaluation and calculations. The engineering basis of the calculation procedures and all inputs and assumptions made in the calculations shall be documented; and

(iv) A description of the parameter or parameters to be monitored to ensure that the control technology will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) The Administrator shall determine within 120 calendar days whether an application presents sufficient information to determine nominal efficiency. The Administrator reserves the right to request specific data in addition to the items listed in paragraph (i)(1) of this section.

(3) The Administrator shall determine within 120 calendar days of the submittal of sufficient data whether a control technology shall have a nominal efficiency and the level of that nominal efficiency. If, in the Administrator's judgment, the control technology achieves a level of emission reduction greater than the reference control technology for a particular kind of emission point, the Administrator will publish aFederal Registernotice 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, aFederal Registernotice 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 aFederal Registernotice; however, this review shall not affect the permitting authority's approval of the nominal efficiency of the control technology for the specific application.

(6) If, in reviewing an application for a control technology for an emission point, the Administrator or permitting authority determines the control technology is not different in use or design from the reference control technology, the Administrator or permitting authority shall deny the application.

(j) The following procedures shall be used for calculating the efficiency (percentage of reduction) of pollution prevention measures:

(1) A pollution prevention measure is any practice that meets the criteria of paragraphs (j)(1)(i) and (j)(1)(ii) of this section.

(i) A pollution prevention measure is any practice that results in a lesser quantity of organic HAP emissions per unit of product released to the atmosphere prior to out-of-process recycling, treatment, or control of emissions while the same product is produced.

(ii) Pollution prevention measures may include: Substitution of feedstocks that reduce HAP emissions, alterations to the production process to reduce the volume of materials released to the environment, equipment modifications; housekeeping measures, and in-process recycling that returns waste materials directly to production as raw materials. Production cutbacks do not qualify as pollution prevention.

(2) The emission reduction efficiency of pollution prevention measures implemented after November 15, 1990 can be used in calculating the actual emissions from an emission point in the debit and credit equations in paragraphs (g) and (h) of this section.

(i) For pollution prevention measures, the percentage of reduction used in the equations in paragraphs (g)(2) and (g)(3) of this section and paragraphs (h)(2) through (h)(4) of this section is the difference in percentage between the monthly organic HAP emissions for each emission point after the pollution prevention measure for the most recent month versus monthly emissions from the same emission point before the pollution prevention measure, adjusted by the volume of product produced during the two monthly periods.

(ii) The following equation shall be used to calculate the percentage of reduction of a pollution prevention measure for each emission point.

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

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:

$$E_B = \sum_{i=1}^{n} \left[ \left(6.0 * 10^{-8}\right) Q_{Bi} \, H_{Bi} \sum_{m=1}^{s} Fe_m HAP_{Bim} \right]$$

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.

$Fe_m$=Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

$HAP_{Bim}$=Average concentration of organic HAP m in wastewater stream i, defined and determined according to paragraph (h)(6)(ii)(A)( *2* ) of this section, before the pollution prevention measure, parts per million by weight, as measured before the implementation of the pollution measure.

(C) If the pollution prevention measure was implemented prior to July 14, 1994, records may be used to determine $E_B$.

(D) The monthly emissions after the pollution prevention measure, $E_{pp}$, may be determined during a performance test or by a design evaluation and documented engineering calculations. Once an emissions-to-production ratio has been established, the ratio can be used to estimate monthly emissions from monthly production records.

(E) For wastewater, $E_{pp}$shall be calculated using the following equation:

$$E_{pp} = \sum_{i=1}^{n} \left[ \left(6.0 * 10^{-8}\right) Q_{ppi} \, H_{ppi} \sum_{m=1}^{s} Fe_m HAP_{ppim} \right]$$

where n, Q, H, s, $Fe_m$, and HAP are defined and determined as described in paragraph (j)(2)(ii)(B) of this section except that $Q_{ppi}$, $H_{ppi}$, and $HAP_{ppim}$shall be determined after the pollution prevention measure has been implemented.

(iii) All equations, calculations, test procedures, test results, and other information used to determine the percentage of reduction achieved by a pollution prevention measure for each emission point shall be fully documented.

(iv) The same pollution prevention measure may reduce emissions from multiple emission points. In such cases, the percentage of reduction in emissions for each emission point must be calculated.

(v) For the purposes of the equations in paragraphs (h)(2) through (h)(6) of this section used to calculate credits for emission points controlled more stringently than the reference control technology, the nominal efficiency of a pollution prevention measure is equivalent to the percentage of reduction of the pollution prevention measure. When a pollution prevention measure is used, the owner or operator of a source is not required to apply to the Administrator for a nominal efficiency and is not subject to paragraph (i) of this section.

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§63.643 through 63.647, and §§63.650 and 63.651.

(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 63.647, and §§63.650 and 63.651.

(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.

(l) 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 §63.654(g)(6).

(2) The owner or operator shall demonstrate that other types of monitoring data or engineering calculations are appropriate to establish that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits. This demonstration shall be made to the Administrator's satisfaction, and the Administrator may establish procedures for demonstrating compliance that are acceptable.

(3) The owner or operator shall provide documentation of the period of excess emissions and the other type of monitoring data or engineering calculations to be used to demonstrate that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits.

(4) The Administrator may assign full or partial credit and debits upon review of the information provided.

[60 FR 43260, Aug. 18, 1995; 60 FR 49976, Sept. 27, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29881, June 12, 1996; 61 FR 33799, June 28, 1996]

## § 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 63.647, and §§63.650 and 63.651. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (a)(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 of this subpart and §63.120 of subpart G; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in §63.646 of this subpart and §63.120(d) of subpart G.

(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 63.647 and §§63.650 and 63.651, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in §63.654(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by §63.654 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by §63.654.

(d) Each owner or operator of an existing source who elects to comply with §63.654 (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 §63.654(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's from wastewater and for which no monitoring parameters or inspection procedures are specified in §63.647, the information specified in §63.654(h)(4) shall be included in the Implementation Plan.

(ix) Documentation required in §63.652(k) demonstrating the hazard or risk equivalency of the proposed emissions average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The Administrator shall either approve the Implementation Plan, request changes, or request that the owner or operator submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 31361, June 9, 1998]

## § 63.654 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), and (h)(1) through (h)(3) of subpart R of this part. 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 §§63.566 and 63.567(a) and §63.567 (c) through (i) of subpart Y of this part. 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)(4). 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)(4) 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 (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. 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) of this subpart.

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (f)(1)(v) of this section.

(i) For storage vessels, this report shall include the information specified in paragraphs (f)(1)(i)(A) through (f)(1)(i)(D) of this section.

(A) Identification of each storage vessel subject to this subpart, and for each Group 1 storage vessel subject to this subpart, the information specified in paragraphs (f)(1)(i)(A)( *1* ) through (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)(4) or to comply with §63.640(l)(3).

( *1* ) For each Group 1 storage vessel complying with §63.646 that is not included in an emissions average, the method of compliance (i.e., internal floating roof, external floating roof, or closed vent system and control device).

( *2* ) For storage vessels subject to the compliance schedule specified in §63.640(h)(4) that are not complying with §63.646, the anticipated compliance date.

( *3* ) For storage vessels subject to the compliance schedule specified in §63.640(h)(4) that are complying with §63.646 and the Group 1 storage vessels described in §63.640(l), the actual compliance date.

(B) If a closed vent system and a control device other than a flare is used to comply with §63.646 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, if the owner or operator elects to prepare a design evaluation; or

( *3* ) If the owner or operator elects to submit the results of a performance test, identification of the storage vessel and control device for which the performance test will be submitted, and identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(C) If a closed vent system and control device other than a flare is used, the owner or operator shall submit:

( *1* ) The operating range for each monitoring parameter. The specified operating range shall represent the conditions for which the control device is being properly operated and maintained.

( *2* ) If a performance test is conducted instead of a design evaluation, results of the performance test demonstrating that the control device achieves greater than or equal to the required control efficiency. A performance test conducted prior to the compliance date of this subpart can be used to comply with this requirement, provided that the test was conducted using EPA methods and that the test conditions are representative of current operating practices.

(D) If a closed vent system and a flare is used, the owner or operator shall submit:

( *1* ) Flare design (e.g., steam-assisted, air-assisted, or nonassisted);

( *2* ) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.120(e) of subpart G of this part; and

( *3* ) All periods during the compliance determination when the pilot flame is absent.

(ii) For miscellaneous process vents, identification of each miscellaneous process vent subject to this subpart, whether the process vent is Group 1 or Group 2, and the method of compliance for each Group 1 miscellaneous process vent that is not included in an emissions average (e.g., use of a flare or other control device meeting the requirements of §63.643(a)).

(iii) For miscellaneous process vents controlled by control devices required to be tested under §63.645 of this subpart and §63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in §63.645 and that the test conditions are representative of current operating conditions.

(A) The percentage of reduction of organic HAP's or TOC, or the outlet concentration of organic HAP's or TOC (parts per million by volume on a dry basis corrected to 3 percent oxygen), determined as specified in §63.116(c) of subpart G of this part; and

(B) The value of the monitored parameters specified in table 10 of this subpart, or a site-specific parameter approved by the permitting authority, averaged over the full period of the performance test,

(iv) For miscellaneous process vents controlled by flares, performance 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 of this subpart and §63.116(a) of subpart G of this part, 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.

(2) If initial performance tests are required by §§63.643 through 63.653 of this subpart, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source.

(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 of this part 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 (f)(3)(iii) of this section.

(i) The specific range of the monitored parameter(s) for each emission point;

(ii) The rationale for the specific range for each parameter for each emission point, including any data and calculations used to develop the range and a description of why the range ensures compliance with the emission standard.

(A) If a performance test is required by this subpart for a control device, the range shall be based on the parameter values measured during the performance test supplemented by engineering assessments and manufacturer's recommendations. Performance testing is not required to be conducted over the entire range of permitted parameter values.

(B) If a performance test is not required by this subpart for a control device, the range may be based solely on engineering assessments and manufacturers' recommendations.

(iii) A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

(4) Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report.

(5) For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for input to the emission credit and debit equations in §63.652(g) and (h), calculated or measured according to the procedures in §63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in §63.640.

(6) Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(4) 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 compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occur. 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 compliance exceptions specified in paragraphs (g)(1) through (g)(6) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emissions 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 if the reports contain the information required by paragraphs (g)(1) through (g)(8) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraph (g)(2) through (g)(5) of this section except that information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source.

(2) 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 of this part in which a failure is detected in the control equipment.

(i) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G of this part, the specifications and requirements listed in paragraphs (g)(2)(i)(A) through (g)(2)(i)(C) of this section apply.

(A) 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.

(B) Except as provided in paragraph (g)(2)(i)(C) 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.

(C) If an extension is utilized in accordance with §63.120(a)(4) of subpart G of this part, 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 of this part; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(ii) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G of this part (i.e., internal inspections), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) and (g)(2)(ii)(B) of this section apply.

(A) 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.

(B) 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.

(3) 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) through (g)(3)(iii) of this section.

(i) 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 of this part in which the seal and seal gap requirements of §63.120(b)(3), (b)(4), (b)(5), or (b)(6) of subpart G of this part are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A) through (g)(3)(i)(D) of this section.

(A) The date of the seal gap measurement.

(B) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (b)(4) of subpart G of this part.

(C) A description of any seal condition specified in §63.120(b)(5) or (b)(6) of subpart G of this part that is not met.

(D) A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

(ii) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G of this part, 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 of this part, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(iii) 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 of this part. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(iii)(A) and (g)(3)(iii)(B) of this section.

(A) 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.

(B) 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.

(4) An owner or operator who elects to comply with §63.646 by using an external floating roof converted to an internal floating roof shall comply with the periodic reporting requirements of paragraph (g)(2) of this section.

(5) An owner or operator who elects to comply with §63.646 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 (g)(5)(iii) of this section.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (g)(5)(i)(B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of §63.119(e)(1) or (e)(2) of subpart G of this part, 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 §63.119 (e)(1) or (e)(2) of subpart G of this part, 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, 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 of this part and shall include: Identification of the flare that does not meet the general requirements specified in §63.11(b) of subpart A of this part, and reasons the flare did not meet the general requirements specified in §63.11(b) of subpart A of this part.

(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 approved under paragraph (h)(5)(iii) of this section, an operating day when the monitor operated for less than 75 percent of the operating hours or a day when less than 18 monitoring values were recorded.

(ii) For miscellaneous process vents, excess emissions shall be reported for the operating parameters specified in table 10 of this subpart unless other site-specific parameter(s) have been approved by the operating permit authority.

(iii) Periods of startup and shutdown that meet the definition of §63.641, and malfunction that meet the definition in §63.2 and periods of performance testing and monitoring system calibration shall not be considered periods of excess emissions. Malfunctions may include process unit, control device, or monitoring system malfunctions.

(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 percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) 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 included in quarterly reports by §§63.567(f) and 63.567(i)(2) of subpart Y of this part 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.

(h) Other reports shall be submitted as specified in subpart A of this part and as follows:

(1) Reports of startup, shutdown, and malfunction required by §63.10(d)(5). Records and reports of startup, shutdown, and malfunction are not required if they pertain solely to Group 2 emission points, as defined in §63.641, that are not included in an emissions average. For purposes of this paragraph, startup and shutdown shall have the meaning defined in §63.641, and malfunction shall have the meaning defined in §63.2; and

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (h)(2)(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), 63.120(a)(3), or 63.120(b)(10) of subpart G of this part 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's, the owner or operator shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. This notification, including the written documentation, may also be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

(C) The State or local permitting authority can waive the notification requirements of paragraphs (h)(2)(i)(A) and/or (h)(2)(i)(B) of this section for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notification required by paragraph (h)(2)(i)(A) of this section, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of this section for all storage vessels, or for individual storage vessels on a case-by-case basis.

(ii) In order to afford the Administrator the opportunity to have an observer present, the owner or operator of a storage vessel equipped with an external floating roof shall notify the Administrator of any seal gap measurements. The notification shall be made in writing at least 30 calendar days in advance of any gap measurements required by §63.120 (b)(1) or (b)(2) of subpart G of this part. The State or local permitting authority can waive this notification requirement for all or some storage vessels subject to the rule or can allow less than 30 calendar days' notice.

(3) For owners or operators of sources required to request approval for a nominal control efficiency for use in calculating credits for an emissions average, the information specified in §63.652(h).

(4) The owner or operator who requests approval to monitor a different parameter than those listed in §63.644 for miscellaneous process vents or who is required by §63.653(a)(8) to establish a site-specific monitoring parameter for a point in an emissions average shall submit the information specified in paragraphs (h)(4)(i) through (h)(4)(iii) of this section. For new or reconstructed sources, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A and for existing sources, and the information shall be submitted no later than 18 months prior to the compliance date. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) A description of the parameter(s) to be monitored to determine whether excess emissions occur and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that they will establish a range for the monitored parameter as part of the Notification of Compliance Status report required in paragraphs (e) and (f) of this section.

(iii) The frequency and content of monitoring, recording, and reporting if: monitoring and recording are not continuous; or if periods of excess emissions, as defined in paragraph (g)(6) of this section, will not be identified in Periodic Reports required under paragraphs (e) and (g) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(5) An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in paragraph (i) of this section.

(i) Requests shall be submitted with the Application for Approval of Construction or Reconstruction for new sources and no later than 18 months prior to the compliance date for existing sources. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. Requests shall contain the information specified in paragraphs (h)(5)(iii) through (h)(5)(iv) of this section, as applicable.

(ii) The provisions in §63.8(f)(5)(i) of subpart A of this part shall govern the review and approval of requests.

(iii) An owner or operator may request approval to use an automated data compression recording system that does not record monitored operating parameter values at a set frequency (for example, once every hour) but records all values that meet set criteria for variation from previously recorded values.

(A) The requested system shall be designed to:

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

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

( *3* ) Record the date and time when monitors are turned off or on.

( *4* ) Recognize unchanging data that may indicate the monitor is not functioning properly, alert the operator, and record the incident.

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

(B) The request shall contain a 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 (h)(5)(iii)(A) of this section.

(iv) An owner or operator may request approval to use other alternative monitoring systems according to the procedures specified in §63.8(f) of subpart A of this part.

(6) The owner or operator shall submit the information specified in paragraphs (h)(6)(i) through (h)(6)(iii) of this section, as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units.

(ii) The determination of applicability of this subpart to any storage vessel for which use varies from year to year.

(iii) The determination of applicability of this subpart to any distillation unit for which use varies from year to year.

(i) *Recordkeeping.* (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 of this part except as specified in paragraphs (i)(1)(i) through (i)(1)(iv) 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 of this part shall be replaced with §63.654(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.

(2) Each owner or operator required to report the results of performance tests under paragraphs (f) and (g)(7) of this section shall retain a record of all reported results as well as a complete test report, as described in paragraph (f)(2)(ii) of this section for each emission point tested.

(3) Each owner or operator required to continuously monitor operating parameters under §63.644 for miscellaneous process vents or under §§63.652 and 63.653 for emission points in an emissions average shall keep the records specified in paragraphs (i)(3)(i) through (i)(3)(v) of this section unless an alternative recordkeeping system has been requested and approved under paragraph (h) of this section.

(i) The monitoring system shall measure data values at least once every hour.

(ii) The owner or operator shall record either:

(A) Each measured data value; or

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

(iii) Daily average values of each continuously monitored parameter shall be calculated for each operating day and retained for 5 years except as specified in paragraph (i)(3)(iv) of this section.

(A) The daily average shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per day if operation is not continuous.

(B) The operating day shall be the period defined in the Notification of Compliance Status report. It may be from midnight to midnight or another daily period.

(iv) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status report, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that day. For these days, the records required in paragraph (i)(3)(ii) of this section shall also be retained for 5 years.

(v) Monitoring data recorded during periods of monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(4) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 44141, Aug. 18, 1998]

## § 63.655 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, and 63.646 through 63.652. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37351, June 23, 2003]

**§§ 63.656-63.679 [Reserved]**

**Appendix to Subpart CC of Part 63—Tables**

**Table 1—Hazardous Air Pollutants**

| Chemical name | CAS No.[a] |
|---|---|
| Benzene | 71432 |
| Biphenyl | 92524 |
| Butadiene (1,3) | 10990 |
| Carbon disulfide | 75150 |
| Carbonyl sulfide | 463581 |
| Cresol (mixed isomers[b]) | 1319773 |
| Cresol (m-) | 108394 |
| Cresol (o-) | 95487 |
| Cresol (p-) | 106445 |
| Cumene | 98828 |
| Dibromoethane (1,2) (ethylene dibromide) | 106934 |
| Dichloroethane (1,2) | 107062 |
| Diethanolamine | 111422 |
| Ethylbenzene | 100414 |
| Ethylene glycol | 107211 |
| Hexane | 110543 |
| Methanol | 67561 |
| Methyl ethyl ketone (2-butanone) | 78933 |
| Methyl isobutyl ketone (hexone) | 108101 |
| Methyl tert butyl ether | 1634044 |
| Naphthalene | 91203 |
| Phenol | 108952 |

| | |
|---|---|
| Toluene | 108883 |
| Trimethylpentane (2,2,4) | 540841 |
| Xylene (mixed isomers[b]) | 1330207 |
| xylene (m-) | 108383 |
| xylene (o-) | 95476 |
| xylene (p-) | 106423 |

[a]CAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

[b]Isomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

**Table 2—Leak Definitions for Pumps and Valves**

| Standard[a] | Phase | Leak definition (parts per million) |
|---|---|---|
| §63.163 (pumps) | I | 10,000 |
| | II | 5,000 |
| | III | 2,000 |
| §63.168 (valves) | I | 10,000 |
| | II | 1,000 |
| | III | 1,000 |

[a]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[a]**

| Reference (section of subpart H of this part) | Description | Comment |
|---|---|---|
| 63.181(a) | Recordkeeping system requirements | Except for §§63.181(b)(2)(iii) and 63.181(b)(9). |
| 63.181(b) | Records required for process unit equipment | Except for §§63.181(b)(2)(iii) and 63.181(b)(9). |
| 63.181(c) | Visual inspection | Except for §§63.181(b)(2)(iii) and |

| | | |
|---|---|---|
| | documentation | 63.181(b)(9). |
| 63.181(d) | Leak detection record requirements | Except for §63.181(d)(8). |
| 63.181(e) | Compliance requirements for pressure tests for batch product process equipment trains | This subsection does not apply to subpart CC. |
| 63.181(f) | Compressor compliance test records. | |
| 63.181(g) | Closed-vent systems and control device record requirements. | |
| 63.181(h) | Process unit quality improvement program records. | |
| 63.181(i) | Heavy liquid service determination record. | |
| 63.181(j) | Equipment identification record. | |
| 63.181(k) | Enclosed-vented process unit emission limitation record requirements. | |
| 63.182(a) | Reports. | |
| 63.182(b) | Initial notification report requirements. | Not required. |
| 63.182(c) | Notification of compliance status report | Except in §63.182(c); change "within 90 days of the compliance dates" to "within 150 days of the compliance dates"; except in §§63.182 (c)(2) and (c)(4). |
| 63.182(d) | Periodic report | Except for §§63.182 (d)(2)(vii), (d)(2)(viii), and (d)(3). |

[a]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[a]**

| Reference (section of | Description | Comment |
|---|---|---|

| | | |
|---|---|---|
| **subpart R of this part)** | | |
| 63.428(b) | Records of test results for each gasoline cargo tank loaded at the facility. | |
| 63.428(c) | Continuous monitoring data recordkeeping requirements. | |
| 63.428(g)(1) | Semiannual report loading rack information | Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC. |
| 63.428 (h)(1) through (h)(3) | Excess emissions report loading rack information | Required to be submitted with the periodic report required under 40 CFR part 63 subpart CC. |

[a]This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

**Table 5—Marine Vessel Loading and Unloading Operations Recordkeeping and Reporting Requirements[a]**

| Reference (section of subpart Y of this part) | Description | Comment |
|---|---|---|
| 63.565(a) | Performance test/site test plan | The information required under this paragraph is to be submitted with the notification of compliance status report required under 40 CFR part 63, subpart CC. |
| 63.565(b) | Performance test data requirements | |
| 63.567(a) | General Provisions (subpart A) applicability | |
| 63.567(c) | Vent system valve bypass recordkeeping requirements | |
| 63.567(d) | Continuous equipment monitoring recordkeeping requirements | |
| 63.567(e) | Flare recordkeeping | |

| | | |
|---|---|---|
| | requirements | |
| 63.567(f) | Quarterly 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(g) | Marine vessel vapor-tightness documentation | |
| 63.567(h) | Documentation file maintenance | |
| 63.567(i) | Emission estimation reporting and recordkeeping procedures | |

[a]This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

**Table 6—General Provisions Applicability to Subpart CC[a]**

| Reference | Applies to subpart CC | Comment |
|---|---|---|
| 63.1(a)(1) | Yes | |
| 63.1(a)(2) | Yes | |
| 63.1(a)(3) | Yes | |
| 63.1(a)(4) | No | Subpart CC (this table) specifies applicability of each paragraph in subpart A to subpart CC. |
| 63.1(a)(5)–63.1(a)(9) | No | |
| 63.1(a)(10) | No | Subpart CC and other cross-referenced subparts specify calendar or operating day. |
| 63.1(a)(11) | Yes | |
| 63.1(a)(12) | Yes | |
| 63.1(a)(13) | Yes | |
| 63.1(a)(14) | Yes | |

| | | |
|---|---|---|
| 63.1(b)(1) | No | Subpart CC specifies its own applicability. |
| 63.1(b)(2) | Yes | |
| 63.1(b)(3) | No | |
| 63.1(c)(1) | No | Subpart CC explicitly specifies requirements that apply. |
| 63.1(c)(2) | No | Area sources are not subject to subpart CC. |
| 63.1(c)(3) | No | |
| 63.1(c)(4) | Yes | |
| 63.1(c)(5) | Yes | Except that sources are not required to submit notifications overridden by this table. |
| 63.1(d) | No | |
| 63.1(e) | No | |
| 63.2 | Yes | §63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC. |
| 63.3 | No | Units of measure are spelled out in subpart CC. |
| 63.4(a)(1)–63.4(a)(3) | Yes | |
| 63.4(a)(4) | No | Reserved. |
| 63.4(a)(5) | Yes | |
| 63.4(b) | Yes | |
| 63.4(c) | Yes | |
| 63.5(a)(1) | Yes | Except replace term “source” and “stationary source” in §63.5(a)(1) of subpart A with “affected source.” |
| 63.5(a)(2) | Yes | |
| 63.5(b)(1) | Yes | |
| 63.5(b)(2) | No | Reserved. |
| 63.5(b)(3) | Yes | |
| 63.5(b)(4) | Yes | Except the cross-reference to §63.9(b) is changed to §63.9(b) (4) and (5). Subpart CC overrides §63.9 (b)(2) and (b)(3). |

| | | |
|---|---|---|
| 63.5(b)(5) | Yes | |
| 63.5(b)(6) | Yes | |
| 63.5(c) | No | Reserved. |
| 63.5(d)(1)(i) | Yes | Except that the application shall be submitted as soon as practicable before startup but no later than 90 days (rather than 60 days) after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC. |
| 63.5(d)(1)(ii) | Yes | Except that for affected sources subject to subpart CC, emission estimates specified in §63.5(d)(1)(ii)(H) are not required. |
| 63.5(d)(1)(iii) | No | Subpart CC requires submittal of the notification of compliance status report in §63.654(e). |
| 63.5(d)(2) | No | |
| 63.5(d)(3) | Yes | Except §63.5(d)(3)(ii) does not apply. |
| 63.5(d)(4) | Yes | |
| 63.5(e) | Yes | |
| 63.5(f)(1) | Yes | |
| 63.5(f)(2) | Yes | Except that the “60 days” in the cross-referenced §63.5(d)(1) is changed to “90 days,” and the cross-reference to (b)(2) does not apply. |
| 63.6(a) | Yes | |
| 63.6(b)(1) | No | Subpart CC specifies compliance dates for sources subject to subpart CC. |
| 63.6(b)(2) | No | |
| 63.6(b)(3) | Yes | |
| 63.6(b)(4) | No | May apply when standards are proposed under section 112(f) of the Clean Air Act. |
| 63.6(b)(5) | No | §63.654(d) of subpart CC includes notification requirements. |
| 63.6(b)(6) | No | |

| | | |
|---|---|---|
| 63.6(b)(7) | No | |
| 63.6(c)(1) | No | §63.640 of subpart CC specifies the compliance date. |
| 63.6(c)(2)–63.6(c)(4) | No | |
| 63.6(c)(5) | Yes | |
| 63.6(d) | No | |
| 63.6(e) | Yes | Does not apply to Group 2 emission points.[b]The startup, shutdown, and malfunction plan specified in §63.6(e)(3) is not required for wastewater operations that are not subject to subpart G of this part. |
| | | Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the startup, shutdown, and malfunction plan do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report. |
| 63.6(f)(1) | Yes | |
| 63.6(f)(2)(i) | Yes | |
| 63.6(f)(2)(ii) | Yes | Subpart CC specifies the use of monitoring data in determining compliance with subpart CC. |
| 63.6(f)(2)(iii) (A), (B), and (C) | Yes | |
| 63.6(f)(2)(iii)(D) | No | |
| 63.6(f)(2)(iv) | Yes | |
| 63.6(f)(2)(v) | Yes | |
| 63.6(f)(3) | Yes | |
| 63.6(g) | Yes | |
| 63.6(h) (1) and (2) | Yes | |
| 63.6(h) (4) and (5) | No | Visible emission requirements and timing in subpart CC. |
| 63.6(h)(6) | Yes | |
| 63.6(h) (7) through (9) | No | Subpart CC does not require opacity standards. |

| | | |
|---|---|---|
| 63.6(i) | Yes | Except for §63.6(i)(15), which is reserved. |
| 63.6(j) | Yes | |
| 63.7(a)(1) | No | Subpart CC specifies required testing and compliance demonstration procedures. |
| 63.7(a)(2) | No | Test results must be submitted in the notification of compliance status report due 150 days after compliance date, as specified in §63.654(d) of subpart CC. |
| 63.7(a)(3) | Yes | |
| 63.7(b) | No | |
| 63.7(c) | No | |
| 63.7(d) | Yes | |
| 63.7(e)(1) | Yes | |
| 63.7(e)(2) | Yes | |
| 63.7(e)(3) | No | Subpart CC specifies test methods and procedures. |
| 63.7(e)(4) | Yes | |
| 63.7(f) | No | Subpart CC specifies applicable methods and provides alternatives. |
| 63.7(g) | No | Performance test reporting specified in §63.654(d). |
| 63.7(h)(1) | Yes | |
| 63.7(h)(2) | Yes | |
| 63.7(h)(3) | Yes | Yes, except site-specific test plans shall not be required, and where §63.7(g)(3) specifies submittal by the date the site-specific test plan is due, the date shall be 90 days prior to the notification of compliance status report in §63.654(d). |
| 63.7(h)(4) | No | |
| 63.7(h)(5) | Yes | |
| 63.8(a) | No | |
| 63.8(b)(1) | Yes | |
| 63.8(b)(2) | No | Subpart CC specifies locations to conduct monitoring. |

| | | |
|---|---|---|
| 63.8(b)(3) | Yes | |
| 63.8(c)(1)(i) | Yes | |
| 63.8(c)(1)(ii) | No | Addressed by periodic reports in §63.654(e) of subpart CC. |
| 63.8(c)(1)(iii) | Yes | |
| 63.8(c)(2) | Yes | |
| 63.8(c)(3) | Yes | Except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately. |
| 63.8(c)(4) | No | Subpart CC specifies monitoring frequency in §63.641 and §63.654(g)(3) of subpart CC. |
| 63.8(c)(5)–63.8(c)(8) | No | |
| 63.8(d) | No | |
| 63.8(e) | No | |
| 63.8(f)(1) | Yes | |
| 63.8(f)(2) | Yes | |
| 63.8(f)(3) | Yes | |
| 63.8(f)(4)(i) | No | Timeframe for submitting request is specified in §63.654(f)(4) of subpart CC. |
| 63.8(f)(4)(ii) | Yes | |
| 63.8(f)(4)(iii) | No | |
| 63.8(f)(5)(i) | Yes | |
| 63.8(f)(5)(ii) | No | |
| 63.8(f)(5)(iii) | Yes | |
| 63.8(f)(6) | No | Subpart CC does not require continuous emission monitors. |
| 63.8(g) | No | Subpart CC specifies data reduction procedures in §63.654(h)(3). |

| | | |
|---|---|---|
| 63.9(a) | Yes | Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in §63.9(a)(4)(ii). |
| 63.9(b)(1)(i) | No | Specified in §63.654(d)(2) of subpart CC. |
| 63.9(b)(1)(ii) | No | |
| 63.9(b)(2) | No | An initial notification report is not required under subpart CC. |
| 63.9(b)(3) | No | |
| 63.9(b)(4) | Yes | Except that the notification in §63.9(b)(4)(i) shall be submitted at the time specified in §63.654(d)(2) of subpart CC. |
| 63.9(b)(5) | Yes | Except that the notification in §63.9(b)(5) shall be submitted at the time specified in §63.654(d)(2) of subpart CC. |
| 63.9(c) | Yes | |
| 63.9(d) | Yes | |
| 63.9(e) | No | |
| 63.9(f) | No | |
| 63.9(g) | No | |
| 63.9(h) | No | Subpart CC §63.652(d) specifies notification of compliance status report requirements. |
| 63.9(i) | Yes | |
| 63.9(j) | No | |
| 63.10(a) | Yes | |
| 63.10(b)(1) | No | §63.644(d) of subpart CC specifies record retention requirements. |
| 63.10(b)(2)(i) | Yes | |
| 63.10(b)(2)(ii) | Yes | |
| 63.10(b)(2)(iii) | No | |
| 63.10(b)(2)(iv) | Yes | |
| 63.10(b)(2)(v) | Yes | |

| | | |
|---|---|---|
| 63.10(b)(2)(vi)–(ix) | No | |
| 63.10(b)(2)(x) | Yes | |
| 63.10(b)(2)(xii)–(xiv) | No | |
| 63.10(b)(3) | No | |
| 63.10(c) | No | |
| 63.10(d)(1) | No | |
| 63.10(d)(2) | No | §63.654(d) of subpart CC specifies performance test reporting. |
| 63.10(d)(3) | No | |
| 63.10(d)(4) | Yes | |
| 63.10(d)(5)(i) | Yes[b] | Except that reports required by §63.10(d)(5)(i) may be submitted at the same time as periodic reports specified in §63.654(e) of subpart CC. |
| 63.10(d)(5)(ii) | Yes | Except that actions taken during a startup, shutdown, or malfunction that are not consistent with the startup, shutdown, and malfunction plan do not need to be reported within 2 and 7 days of commencing and completing the action, respectively, but must be included in the next periodic report. |
| 63.10(e) | No | |
| 63.10(f) | Yes | |
| 63.11–63.15 | Yes | |

[a]Wherever subpart A 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.

[b]The plan, and any records or reports of startup, shutdown, and malfunction do not apply to Group 2 emission points.

**Table 7—Fraction Measured ($F_m$), Fraction Emitted ($F_e$), and Fraction Removed (Fr) for HAP Compounds in Wastewater Streams**

| Chemical name | CAS No.[a] | $F_m$ | $F_e$ | Fr |
|---|---|---|---|---|
| Benzene | 71432 | 1.00 | 0.80 | 0.99 |

| | | | | |
|---|---|---|---|---|
| Biphenyl | 92524 | 0.86 | 0.45 | 0.99 |
| Butadiene (1,3-) | 106990 | 1.00 | 0.98 | 0.99 |
| Carbon disulfide | 75150 | 1.00 | 0.92 | 0.99 |
| Cumene | 98828 | 1.00 | 0.88 | 0.99 |
| Dichloroethane (1,2-) (Ethylene dichloride) | 107062 | 1.00 | 0.64 | 0.99 |
| Ethylbenzene | 100414 | 1.00 | 0.83 | 0.99 |
| Hexane | 110543 | 1.00 | 1.00 | 0.99 |
| Methanol | 67561 | 0.85 | 0.17 | 0.31 |
| Methyl ethyl ketone (2-Butanone) | 78933 | 0.99 | 0.48 | 0.95 |
| Methyl isobutyl ketone (Hexone) | 108101 | 0.98 | 0.53 | 0.99 |
| Methyl tert-butyl ether | 1634044 | 1.00 | 0.57 | 0.99 |
| Naphthalene | 91203 | 0.99 | 0.51 | 0.99 |
| Trimethylpentane (2,2,4-) | 540841 | 1.00 | 1.00 | 0.99 |
| Xylene (m-) | 108383 | 1.00 | 0.82 | 0.99 |
| Xylene (o-) | 95476 | 1.00 | 0.79 | 0.99 |
| Xylene (p-) | 106423 | 1.00 | 0.82 | 0.99 |

[a]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**

| Performance level | Valve monitoring frequency |
|---|---|
| Leaking valves[a](%) | |
| ≥4 | Monthly or QIP.[b] |
| <4 | Quarterly. |
| <3 | Semiannual. |
| <2 | Annual. |

[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 9—Valve Monitoring Frequency for Alternative**

| Performance level<br>Leaking valves[a](%) | Valve monitoring frequency under §63.649 alternative |
|---|---|
| ≥5 | Monthly or QIP.[b] |
| <5 | Quarterly. |
| <4 | Semiannual. |
| <3 | Annual. |

[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**

| Control device | Parameters to be monitored[a] | Recordkeeping and reporting requirements for monitored parameters |
|---|---|---|
| Thermal incinerator | Firebox temperature[b](63.644(a)(1)(i)) | 1. Continuous records[c]. |
| | | 2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d]. |
| | | 3. Record the daily average firebox temperature for each operating day[e]. |
| | | 4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g]. |
| Catalytic incinerator | Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii)) | 1. Continuous records[c]. |
| | | 2. Record and report the |

| | | |
|---|---|---|
| | | upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test—NCS[d]. |
| | | 3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day[e]. |
| | | 4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR[g]. |
| | | 5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR[g]. |
| | | 6. Report all operating days when insufficient monitoring data are collected[f]. |
| Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is *not* introduced into the flame zone[h,i] | Firebox temperature[b](63.644(a)(4)) | 1. Continuous records[c]. |
| | | 2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d]. |
| | | 3. Record the daily average firebox temperature for each operating day[e]. |

| | | |
|---|---|---|
| | | 4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g]. |
| Flare | Presence of a flame at the pilot light (63.644(a)(2)) | 1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour. |
| | | 2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS[d]. |
| | | 3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating. |
| | | 4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating. |
| All control devices | Presence of flow diverted to the atmosphere from the control device (63.644(c)(1)) *or* | 1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour. |
| | | 2. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR[g]. |
| | Monthly inspections of sealed valves [63.644(c)(2)] | 1. Records that monthly inspections were performed. |

| | | |
|---|---|---|
| | | 2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR[g]. |

[a]Regulatory citations are listed in parentheses.

[b]Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

[c]"Continuous records" is defined in §63.641.

[d]NCS = Notification of compliance status report described in §63.654.

[e]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.

[f]When a period of excess emission is caused by insufficient monitoring data, as described in §63.654(g)(6)(i)(C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

[g]PR = Periodic Reports described in §63.654(g).

[h]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.

[i]Process vents that are routed to refinery fuel gas systems are not regulated under this subpart. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, 29882, June 12, 1996; 63 FR 44142, 44143, Aug. 18, 1998]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment E
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart GGG—Standards of Performance 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**

**Source:** 49 FR 22606, May 30, 1984, unless otherwise noted.

**§ 60.590 Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 4, 1983, and on or before November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.591) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, or subpart KKK of this part are excluded from this subpart.

(e) *Stay of standards* . Owners or operators are not required to comply with the definition of “process unit” in §60.590 of this subpart until August 1, 2008. While the definition of “process unit” is stayed, owners or operators should use the following definition:

*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

[49 FR 22606, May 30, 1984, as amended at 72 FR 64895, Nov. 16, 2007]

**§ 60.591 Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the act, in subpart A of part 60, or in subpart VV of part 60, and the following terms shall have the specific meanings given them.

*Alaskan North Slope* means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

*Asphalt* (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.

*Equipment* means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

*In hydrogen service* means that a compressor contains a process fluid that meets the conditions specified in §60.593(b).

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in §60.593(c).

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

[49 FR 22606, May 30, 1984, as amended at 72 FR 64895, Nov. 16, 2007]

## § 60.592 Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.482–1 to 60.482–10 as soon as practicable, but no later than 180 days after initial startup.

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in §60.482–7.

(1) Comply with §60.483–1.

(2) Comply with §60.483–2.

(3) Comply with the Phase III provisions in 40 CFR 63.168, except an owner or operator may elect to follow the provisions in §60.482–7(f) instead of 40 CFR 63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in

emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.484.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485 except as provided in §60.593.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486 and 60.487.

[49 FR 22606, May 30, 1984, as amended at 72 FR 64896, Nov. 16, 2007]

## § 60.593 Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

(b)(1) Compressors in hydrogen service are exempt from the requirements of §60.592 if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) 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. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482–3(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §60.482–3(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to §60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §60.482–2 and §60.482–7.

(f) Open-ended valves or lines containing asphalt as defined in §60.591 are exempt from the requirements of §60.482–6(a) through (c).

[49 FR 22606, May 30, 1984, as amended at 65 FR 61768, Oct. 17, 2000; 72 FR 64896, Nov. 16, 2007]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment F
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart QQQ—Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems**

**Source:** 53 FR 47623, Nov. 23, 1988, unless otherwise noted.

**§ 60.690 Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987.

(2) An individual drain system is a separate affected facility.

(3) An oil-water separator is a separate affected facility.

(4) An aggregate facility is a separate affected facility.

(b) Notwithstanding the provisions of 40 CFR 60.14(e)(2), the construction or installation of a new individual drain system shall constitute a modification to an affected facility described in §60.690(a)(4). For purposes of this paragraph, a new individual drain system shall be limited to all process drains and the first common junction box.

**§ 60.691 Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of 40 CFR part 60, and the following terms shall have the specific meanings given them.

*Active service* means that a drain is receiving refinery wastewater from a process unit that will continuously maintain a water seal.

*Aggregate facility* means an individual drain system together with ancillary downstream sewer lines and oil-water separators, down to and including the secondary oil-water separator, as applicable.

*Catch basin* means an open basin which serves as a single collection point for stormwater runoff received directly from refinery surfaces and for refinery wastewater from process drains.

*Closed vent system* means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission source to

a control device. If gas or vapor from regulated equipment are 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 the closed vent system standards.

*Completely closed drain system* means an individual drain system that is not open to the atmosphere and is equipped and operated with a closed vent system and control device complying with the requirements of §60.692–5.

*Control device* means an enclosed combustion device, vapor recovery system or flare.

*Fixed roof* means a cover that is mounted to a tank or chamber in a stationary manner and which does not move with fluctuations in wastewater levels.

*Floating roof* means a pontoon-type or double-deck type cover that rests on the liquid surface.

*Gas-tight* means operated with no detectable emissions.

*Individual drain system* means all process drains connected to the first common downstream junction box. The term includes all such drains and common junction box, together with their associated sewer lines and other junction boxes, down to the receiving oil-water separator.

*Junction box* means a manhole or access point to a wastewater sewer system line.

*No detectable emissions* means less than 500 ppm above background levels, as measured by a detection instrument in accordance with Method 21 in appendix A of 40 CFR part 60.

*Non-contact cooling water system* means a once-through drain, collection and treatment system designed and operated for collecting cooling water which does not come into contact with hydrocarbons or oily wastewater and which is not recirculated through a cooling tower.

*Oil-water separator* means wastewater treatment equipment used to separate oil from water consisting of a separation tank, which also includes the forebay and other separator basins, skimmers, weirs, grit chambers, and sludge hoppers. Slop oil facilities, including tanks, are included in this term along with storage vessels and auxiliary equipment located between individual drain systems and the oil-water separator. This term does not include storage vessels or auxiliary equipment which do not come in contact with or store oily wastewater.

*Oily wastewater* means wastewater generated during the refinery process which contains oil, emulsified oil, or other hydrocarbons. Oily wastewater originates from a variety of refinery processes including cooling water, condensed stripping steam, tank draw-off, and contact process water.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation of petroleum, cracking, or reforming unfinished petroleum derivatives.

*Sewer line* means a lateral, trunk line, branch line, ditch, channel, or other conduit used to convey refinery wastewater to downstream components of a refinery wastewater treatment system. This term does not include buried, below-grade sewer lines.

*Slop oil* means the floating oil and solids that accumulate on the surface of an oil-water separator.

*Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, including oily wastewater.

*Stormwater sewer system* means a drain and collection system designed and operated for the sole purpose of collecting stormwater and which is segregated from the process wastewater collection system.

*Wastewater system* means any component, piece of equipment, or installation that receives, treats, or processes oily wastewater from petroleum refinery process units.

*Water seal controls* means a seal pot, p-leg trap, or other type of trap filled with water that has a design capability to create a water barrier between the sewer and the atmosphere.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

## § 60.692-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.692–1 to 60.692–5 and with §§60.693–1 and 60.693–2, except during periods of startup, shutdown, or malfunction.

(b) Compliance with §§60.692–1 to 60.692–5 and with §§60.693–1 and 60.693–2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.696.

(c) Permission to use alternative means of emission limitation to meet the requirements of §§60.692–2 through 60.692–4 may be granted as provided in §60.694.

(d)(1) Stormwater sewer systems are not subject to the requirements of this subpart.

(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.

(3) Non-contact cooling water systems are not subject to the requirements of this subpart.

(4) An owner or operator shall demonstrate compliance with the exclusions in paragraphs (d)(1), (2), and (3) of this section as provided in §60.697 (h), (i), and (j).

## § 60.692-2 Standards: Individual drain systems.

(a)(1) Each drain shall be equipped with water seal controls.

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.

(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.

(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in §60.692–6.

(b)(1) Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(2) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(3) Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(4) If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in §60.692–6.

(c)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in §60.692–6.

(d) Except as provided in paragraph (e) of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

(e) Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

### § 60.692-3 Standards: Oil-water separators.

(a) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph (d) of this section or in §60.693–2.

(1) The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.

(2) The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.

(3) If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.

(4) Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

(5) When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in §60.692–6.

(b) Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph (a) of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of §60.692–5, except as provided in paragraph (c) of this section or in §60.693–2.

(c)(1) Each modified or reconstructed oil-water separator tank with a maximum design capacity to treat less than 38 liters per second (600 gpm) of refinery wastewater which was equipped and operated with a fixed roof covering the entire separator tank or a portion of the separator tank prior to May 4, 1987 shall be exempt from the requirements of paragraph (b) of this section, but shall meet the requirements of paragraph (a) of this section, or may elect to comply with paragraph (c)(2) of this section.

(2) The owner or operator may elect to comply with the requirements of paragraph (a) of this section for the existing fixed roof covering a portion of the separator tank and comply with the requirements for floating roofs in §60.693–2 for the remainder of the separator tank.

(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

(e) Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph (a) of this section.

(f) Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph (a) of this section, and not paragraph (b) of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

## § 60.692-4 Standards: Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of §§60.692–2 and 60.692–3.

## § 60.692-5 Standards: Closed vent systems and control devices.

(a) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C (1,500 °F).

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(c) Flares used to comply with this subpart shall comply with the requirements of 40 CFR 60.18.

(d) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(e)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in §60.696.

(2) Closed vent systems shall be purged to direct vapor to the control device.

(3) A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.

(4) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(5) When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in §60.692–6.

### § 60.692-6 Standards: Delay of repair.

(a) Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.

(b) Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

### § 60.692-7 Standards: Delay of compliance.

(a) Delay of compliance of modified individual drain systems with ancillary downstream treatment components will be allowed if compliance with the provisions of this subpart cannot be achieved without a refinery or process unit shutdown.

(b) Installation of equipment necessary to comply with the provisions of this subpart shall occur no later than the next scheduled refinery or process unit shutdown.

### § 60.693-1 Alternative standards for individual drain systems.

(a) An owner or operator may elect to construct and operate a completely closed drain system.

(b) Each completely closed drain system shall be equipped and operated with a closed vent system and control device complying with the requirements of §60.692–5.

(c) An owner or operator must notify the Administrator in the report required in 40 CFR 60.7 that the owner or operator has elected to construct and operate a completely closed drain system.

(d) If an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of §60.692–2 or §60.694.

(e)(1) Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(2) The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

(3) Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in §60.692–6.

### § 60.693-2 Alternative standards for oil-water separators.

(a) An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.

(1) Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.

(i) The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

(A) A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(B) The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.

(C) The total gap area between the primary seal and the separator wall shall not exceed 67 $cm^2$ /m (3.2 $in.^2$ /ft) of separator wall perimeter.

(ii) The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.

(A) The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

(B) The total gap area between the secondary seal and the separator wall shall not exceed 6.7 $cm^2$ /m (0.32 $in.^2$ /ft) of separator wall perimeter.

(iii) The maximum gap width and total gap area shall be determined by the methods and procedures specified in §60.696(d).

(A) Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.

(B) Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.

(iv) The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs (a)(1) (i) and (ii) of this section.

(2) Except as provided in paragraph (a)(4) of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.

(3) The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).

(4) The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.

(5)(i) Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.

(ii) When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in §60.692–6.

(b) An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph (a) of this section.

(c) For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of §60.692–3(a) shall be installed.

(d) Except as provided in paragraph (c) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of §§60.692–3 or 60.694 applicable to the same facilities.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

## § 60.694 Permission to use alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved by the applicable requirement in §60.692, the Administrator will publish in theFederal Registera notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

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

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

## § 60.695 Monitoring of operations.

(a) Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

(1) Where a thermal incinerator is used for VOC emission reduction, a temperature monitoring device equipped with a continuous recorder shall be used to measure the temperature of the gas stream in the combustion zone of the incinerator. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being measured, expressed in °C, or ±0.5 °C (0.9 °F), whichever is greater.

(2) Where a catalytic incinerator is used for VOC emission reduction, temperature monitoring devices, each equipped with a continuous recorder shall be used to measure the temperature in the gas stream immediately before and after the catalyst bed of the incinerator. The temperature monitoring devices shall have an accuracy of ±1 percent of the temperature being measured, expressed in °C, or ±0.5 °C (0.9 °F), whichever is greater.

(3) Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(i) For a carbon adsorption system that regenerates the carbon bed directly onsite, a monitoring device that continuously indicates and records the volatile organic compound concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time

interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

(4) Where a flare is used for VOC emission reduction, the owner or operator shall comply with the monitoring requirements of 40 CFR 60.18(f)(2).

(b) Where a VOC recovery device other than a carbon adsorber is used to meet the requirements specified in §60.692–5(a), the owner or operator shall provide to the Administrator information describing the operation of the control device and the process parameter(s) that would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(c) An alternative operational or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

## § 60.696 Performance test methods and procedures and compliance provisions.

(a) Before using any equipment installed in compliance with the requirements of §60.692–2, §60.692–3, §60.692–4, §60.692–5, or §60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

(b) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.692–5 (other than a flare) is exempt from §60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

(1) Zero air (less than 10 ppm of hydrocarbon in air), and

(2) A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall conduct a performance test initially, and at other times as requested by the Administrator, using the test methods and procedures in §60.18(f) to determine compliance of flares.

(d) After installing the control equipment required to meet §60.693–2(a) or whenever sources that have ceased to treat refinery wastewater for a period of 1 year or more are placed back into service, the owner or operator shall determine compliance with the standards in §60.693–2(a) as follows:

(1) The maximum gap widths and maximum gap areas between the primary seal and the separator wall and between the secondary seal and the separator wall shall be determined individually within 60 calendar days of the initial installation of the floating roof and introduction of refinery wastewater or 60 calendar days after the equipment is placed back into service using the following procedure when the separator is filled to the design operating level and when the roof is floating off the roof supports.

(i) Measure seal gaps around the entire perimeter of the separator in each place where a 0.32 cm (0.125 in.) diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the separator and measure the gap width and perimetrical distance of each such location.

(ii) The total surface area of each gap described in (d)(1)(i) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the wall to the seal and multiplying each such width by its respective perimetrical distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually, divide the sum for each seal by the nominal perimeter of the separator basin and compare each to the maximum gap area as specified in §60.693–2.

(2) The gap widths and total gap area shall be determined using the procedure in paragraph (d)(1) of this section according to the following frequency:

(i) For primary seals, once every 5 years.

(ii) For secondary seals, once every year.

## § 60.697 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

(b)(1) For individual drain systems subject to §60.692–2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

(2) For junction boxes subject to §60.692–2, the location, date, and corrective action shall be recorded for inspections required by §60.692–2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

(3) For sewer lines subject to §§60.692–2 and 60.693–1(e), the location, date, and corrective action shall be recorded for inspections required by §§60.692–2(c) and 60.693–1(e) when a problem is identified that could result in VOC emissions.

(c) For oil-water separators subject to §60.692–3, the location, date, and corrective action shall be recorded for inspections required by by §60.692–3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to §60.692–5 and completely closed drain systems subject to §60.693–1, the location, date, and corrective action shall be recorded for inspections required by §60.692–5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.

(e)(1) If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

(2) The reason for the delay as specified in §60.692–6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

(3) The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

(4) The date of successful repair or corrective action shall be recorded.

(f)(1) A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

(2) The following information pertaining to the design specifications shall be kept.

(i) Detailed schematics, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(3) The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

(ii) For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(iii) Periods when the closed vent systems and control devices required in §60.692 are not operated as designed, including periods when a flare pilot does not have a flame shall be recorded and kept for 2 years after the information is recorded.

(iv) Dates of startup and shutdown of the closed vent system and control devices required in §60.692 shall be recorded and kept for 2 years after the information is recorded.

(v) The dates of each measurement of detectable emissions required in §§60.692, 60.693, or 60.692–5 shall be recorded and kept for 2 years after the information is recorded.

(vi) The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

(vii) The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

(viii) Each owner or operator of an affected facility that uses a thermal incinerator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each owner or operator of an affected facility that uses a catalytic incinerator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(A) Each owner or operator of an affected facility that uses a carbon adsorber which is regenerated directly onsite shall maintain continuous records of the volatile organic compound concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

(B) If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

(g) If an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains.

(h) For stormwater sewer systems subject to the exclusion in §60.692–1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

(i) For ancillary equipment subject to the exclusion in §60.692–1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonsrate that the ancillary equipment does not come in contact with or store oily wastewater.

(j) For non-contact cooling water systems subject to the exclusion in §60.692–1(d)(3), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.

(k) For oil-water separators subject to §60.693–2, the location, date, and corrective action shall be recorded for inspections required by §§60.693–2(a)(1)(iii)(A) and (B), and shall be maintained for the time period specified in paragraphs (k)(1) and (2) of this section.

(1) For inspections required by §60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

(2) For inspections required by §60.693–2(a)(1)(iii)(B), two years after the information is recorded.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

## § 60.698 Reporting requirements.

(a) An owner or operator electing to comply with the provisions of §60.693 shall notify the Administrator of the alternative standard selected in the report required in §60.7.

(b)(1) Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

(2) Each owner or operator of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under §60.8(a), a report of the results of the performance test required in §60.696(c).

(c) A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.

(d) As applicable, a report shall be submitted semiannually to the Administrator that indicates:

(1) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature,

(2) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference, or,

(3) Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

(i) Each 3-hour period of operation during which the average volatile organic compound concentration level or reading of organics in the exhaust gases from a carbon adsorber which is regenerated directly onsite is more than 20 percent greater than the design exhaust gas concentration level or reading.

(ii) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in §60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to §60.692–7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

[53 FR 47623, Nov. 23, 1988, as amended at 60 FR 43260, Aug. 18, 1995]

## § 60.699 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States:

§60.694 Permission to use alternative means of emission limitations.

[53 FR 47623, Nov. 23, 1985]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment G
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

**Source:** 72 FR 32759, June 13, 2007, unless otherwise noted.

**§ 60.40c Applicability and delegation of authority.**

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide ($SO_2$) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not covered by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not covered by this subpart.

## § 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

*Annual capacity factor* means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

*Cogeneration steam generating unit* means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

*Combined cycle system* means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

*Combustion research* means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit ( *i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

*Conventional technology* means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

*Dry flue gas desulfurization technology* means a $SO_2$control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

*Emerging technology* means any $SO_2$control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fluidized bed combustion technology* means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

*Fuel pretreatment* means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

*Heat input* means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

*Heat transfer medium* means any material that is used to transfer heat from one point to another point.

*Maximum design heat input capacity* means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

*Natural gas* means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

*Potential sulfur dioxide emission rate* means the theoretical $SO_2$emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

*Steam generating unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

*Wet flue gas desulfurization technology* means an $SO_2$control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or $SO_2$.

*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

## § 60.42c Standard for sulfur dioxide ($SO_2$).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential $SO_2$emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of $SO_2$in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input $SO_2$emissions limit or the 90 percent $SO_2$reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of $SO_2$emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of 50 percent (0.50) of the potential $SO_2$emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent $SO_2$reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$in excess of the following:

(1) The percent of potential $SO_2$emission rate or numerical $SO_2$emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

$E_s$= $SO_2$emission limit, expressed in ng/J or lb/MMBtu heat input;

$K_a$= 520 ng/J (1.2 lb/MMBtu);

$K_b$= 260 ng/J (0.60 lb/MMBtu);

$K_c$= 215 ng/J (0.50 lb/MMBtu);

$H_a$= Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

$H_b$= Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

$H_cK_aH_b$= Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential $SO_2$emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential $SO_2$emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion $SO_2$control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The $SO_2$emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

## § 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into

the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or $SO_2$emissions is not subject to the PM limit in this section.

## § 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and $SO_2$emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and $SO_2$emission limits under §60.42c is based on the average percent reduction and the average $SO_2$emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and $SO_2$emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly $SO_2$emission rate ($E_{ho}$) and the 30-day average $SO_2$emission rate ($E_{ao}$). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate $E_{ao}$when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted $E_{ho}$($E_{ho}$o) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted $E_{ao}$($E_{ao}$o). The $E_{ho}$o is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_j)}{X_j}$$

Where:

$E_{ho}$o = Adjusted $E_{ho}$, ng/J (lb/MMBtu);

$E_{ho}$= Hourly $SO_2$emission rate, ng/J (lb/MMBtu);

$E_w$= $SO_2$concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J

(lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$if the owner or operator elects to assume $E_w$= 0.

$X_k$= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters $E_w$or $X_k$if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the $SO_2$emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential $SO_2$emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential $SO_2$emission rate, in percent;

$\%R_g$= $SO_2$removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= $SO_2$removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$($\%R_g$o) is computed from $E_{ao}$o from paragraph (e)(1) of this section and an adjusted average $SO_2$inlet rate ($E_{ai}$o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^{\circ}_{ao}}{E^{\circ}_{ai}}\right)$$

Where:

$\%R_g$o = Adjusted $\%R_g$, in percent;

$E_{ao}$o = Adjusted $E_{ao}$, ng/J (lb/MMBtu); and

$E_{ai}$o = Adjusted average $SO_2$inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly $SO_2$inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hi}o$ = Adjusted $E_{hi}$, ng/J (lb/MMBtu);

$E_{hi}$= Hourly $SO_2$inlet rate, ng/J (lb/MMBtu);

$E_w$= $SO_2$concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$if the owner or operator elects to assume $E_w$= 0; and

$X_k$= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the $SO_2$standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the $SO_2$standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid $SO_2$emissions data in calculating $\%P_s$and $E_{ho}$under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$or $E_{ho}$pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

### § 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent

performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3 of appendix A of this part shall be used for gas analysis when applying Method 5, 5B, or 17 of appendix A of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen ($O_2$) or carbon dioxide ($CO_2$) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The $O_2$or $CO_2$measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A of this part (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(13) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (d)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (d)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (d)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and $O_2$(or $CO_2$) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For $O_2$(or $CO_2$), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

## § 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the $SO_2$emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring $SO_2$concentrations and either $O_2$or $CO_2$concentrations at the outlet of the $SO_2$control device (or the outlet of the steam generating unit if no $SO_2$control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure $SO_2$concentrations and either $O_2$or $CO_2$concentrations at both the inlet and outlet of the $SO_2$control device.

(b) The 1-hour average $SO_2$emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average $SO_2$emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly $SO_2$emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the $SO_2$CEMS at the inlet to the $SO_2$control device shall be 125 percent of the maximum estimated hourly potential $SO_2$emission rate of the fuel combusted, and the span value of the $SO_2$CEMS at the outlet from the $SO_2$control device shall be 50 percent of the maximum estimated hourly potential $SO_2$emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the $SO_2$CEMS at the outlet from the $SO_2$control device (or outlet of the steam generating unit if no $SO_2$control device is used) shall be 125 percent of the maximum estimated hourly potential $SO_2$emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the $SO_2$control device (or outlet of the steam generating unit if no $SO_2$control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the $SO_2$control device (or outlet of the steam generating unit if no $SO_2$control device is used) as required under paragraph (a) of this section, an owner or

operator may elect to determine the average $SO_2$emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average $SO_2$input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure $SO_2$at the inlet or outlet of the $SO_2$control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and $CO_2$measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the $SO_2$standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

## § 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.06 lb/MMBtu) heat input or

less and that do not use a post-combustion technology to reduce $SO_2$or PM emissions are not required to operate a CEMS for measuring opacity if they follow the applicable procedures under §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.45c(d). The CEMS specified in paragraph §60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) An affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS for measuring opacity. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An affected facility that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority is not required to operate a COMS for measuring opacity. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

## § 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling $SO_2$emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the $SO_2$emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) The owner or operator of each coal-fired, oil-fired, or wood-fired affected facility subject to the opacity limits under §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period.

(d) The owner or operator of each affected facility subject to the $SO_2$emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the $SO_2$emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average $SO_2$emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential $SO_2$emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which $SO_2$or diluent ($O_2$or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the $SO_2$standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the $SO_2$standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment H
## for a
## Part 70 Operating Permit

### Source Background and Description

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

### Subpart J—Standards of Performance for Petroleum Refineries

### § 60.100 Applicability, designation of affected facility, and reconstruction.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare as defined in §60.101a which commences construction, reconstruction, or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that meets the definition of a flare as defined in §60.101a which commences construction, reconstruction, or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction, or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from §60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

(e) For purposes of this subpart, under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[43 FR 10868, Mar. 15, 1978, as amended at 44 FR 61543, Oct. 25, 1979; 54 FR 34026, Aug. 17, 1989; 73 FR 35865, June 24, 2008]

## § 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) *Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) *Process gas* means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted to comply with the wastewater provisions in §60.692, 40 CFR 61.343 through 61.348, or 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

(e) *Process upset gas* means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) *Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) *Fuel gas combustion device* means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) *Coke burn-off* means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.106.

(i) *Claus sulfur recovery plant* means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) *Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) *Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) *Reduced sulfur compounds* means hydrogen sulfide ($H_2S$), carbonyl sulfide (COS) and carbon disulfide ($CS_2$).

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) *Fluid catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) *Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A “valid hour” is one in which at least 2 valid data points are obtained.

[39 FR 9315, Mar. 8, 1974, as amended at 43 FR 10868, Mar. 15, 1978; 44 FR 13481, Mar. 12, 1979; 45 FR 79453, Dec. 1, 1980; 54 FR 34027, Aug. 17, 1989; 73 FR 35865, June 24, 2008]

## § 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

[39 FR 9315, Mar. 8, 1974, as amended at 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10868, Feb. 15, 1978; 54 FR 34027, Aug. 17, 1989; 65 FR 61753, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

## § 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis).

[54 FR 34027, Aug. 17, 1989, as amended at 55 FR 40175, Oct. 2, 1990]

## § 60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide ($H_2S$) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide ($SO_2$) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide ($H_2S$), each calculated as ppm $SO_2$by volume (dry basis) at zero percent excess air.

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce $SO_2$ emissions to the atmosphere by 90 percent or maintain $SO_2$ emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce $SO_2$ emission, maintain sulfur oxides emissions calculated as $SO_2$ to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in §60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

[43 FR 10869, Mar. 15, 1978, as amended at 54 FR 34027, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

## § 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

(1) For fluid catalytic cracking unit catalyst regenerators subject to §60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to §60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2) (ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in §10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to §60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of $SO_2$ emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess.

(i) The span values for this monitor are 50 ppm $SO_2$ and 25 percent oxygen ($O_2$).

(ii) The $SO_2$ monitoring level equivalent to the $H_2S$ standard under §60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this $SO_2$ monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the $SO_2$emissions into the atmosphere from each of the combustion devices.

(4) Instead of the $SO_2$ monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to §60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of $H_2S$ in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm $H_2S$.

(ii) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of $H_2S$ in the fuel gas being burned.

(iii) The performance evaluations for this $H_2S$ monitor under §60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under §60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under §60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this

section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to §60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of $SO_2$emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm $SO_2$ and 25 percent $O_2$.

(ii) The performance evaluations for this $SO_2$ monitor under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to §60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and $O_2$emissions into the atmosphere. The reduced sulfur emissions shall be calculated as $SO_2$ (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 25 percent $O_2$.

(ii) The performance evaluations for this reduced sulfur (and $O_2$) monitor under §60.13(c) shall use Performance Specification 5 of appendix B of this part (and Performance Specification 3 of appendix B of this part for the $O_2$ analyzer). Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields $O_2$ concentrations below 0.25 percent during the performance specification test, the $O_2$ concentration may be assumed to be zero and the reduced sulfur CEMS need not include an $O_2$ monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or $O_2$ dilution and oxidation system to convert the reduced sulfur to $SO_2$ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant $SO_2$. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm $SO_2$and 25 percent $O_2$.

(ii) For reporting purposes, the $SO_2$ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this $SO_2$ (and $O_2$) monitor under §60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

(8) An instrument for continuously monitoring and recording concentrations of $SO_2$ in the gases at both the inlet and outlet of the $SO_2$ control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under §60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential $SO_2$emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential $SO_2$ emission concentration entering the control device.

(ii) The performance evaluations for these $SO_2$ monitors under §60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(9) An instrument for continuously monitoring and recording concentrations of $SO_2$ in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 ppmv emission limit under §60.104 (b)(1).

(i) The span value of the monitor shall be set at 50 percent of the maximum hourly potential $SO_2$ emission concentration of the control device.

(ii) The performance evaluations for this $SO_2$ monitor under §60.13 (c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(10) An instrument for continuously monitoring and recording concentrations of oxygen ($O_2$) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 ppmv standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with §60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall use the following procedures to evaluate the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(i) Method 3 or 3A and Method 6 or 6C for the relative accuracy evaluations under the §60.13(e) performance evaluation.

(ii) appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests.

(13) When seeking to comply with §60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The test methods as described in §60.106(k);

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1) that is not specifically exempted in §60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in

paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system, and the affected fuel gas combustion device(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high $H_2S$ content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see §60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for $H_2S$; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of $H_2S$ concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting $H_2S$ content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an $H_2S$ test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin $H_2S$ monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour $H_2S$ concentration limit. The owner or operator must determine a rolling 365-day average using the stain sampling results; an average $H_2S$ concentration of 5 ppmv must be used for days prior to the operation change.

(c) The average coke burn-off rate (Mg (tons) per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to §60.102, §60.103, or §60.104(b)(2).

(d) For any fluid catalytic cracking unit catalyst regenerator under §60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under §60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

Note: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity.* All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under §60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide.* All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion.* (i) All rolling 3-hour periods during which the average concentration of $SO_2$ as measured by the $SO_2$ continuous monitoring system under §60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of $H_2S$ as measured by the $H_2S$ continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants.* (i) All 12-hour periods during which the average concentration of $SO_2$ as measured by the $SO_2$continuous monitoring system under §60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as $SO_2$) as measured by the reduced sulfur continuous monitoring system under §60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of $SO_2$ as measured by the $SO_2$ continuous monitoring system under §60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

[39 FR 9315, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975; 42 FR 32427, June 24, 1977; 42 FR 39389, Aug. 4, 1977; 43 FR 10869, Mar. 15, 1978; 48 FR 23611, May 25, 1983; 50 FR 31701, Aug. 5, 1985; 54 FR 34028, Aug. 17, 1989; 55 FR 40175, Oct. 2, 1990; 65 FR 61754, Oct. 17, 2000; 73 FR 35866, June 24, 2008]

## § 60.106 Test methods and procedures.

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

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in §60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = \frac{c_s Q_{sd}}{K R_c}$$

Where:

E = Emission rate of PM, kg/Mg (lb/ton) of coke burn-off.

$c_s$= Concentration of PM, g/dscm (gr/dscf).

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

$R_c$= Coke burn-off rate, Mg/hr (ton/hr) coke.

K=Conversion factor, 1,000 g/kg (7,000 gr/lb).

(2) Method 5B or 5F is to be used to determine particulate matter emissions and associated moisture content from affected facilities without wet FGD systems; only Method 5B is to be used after wet FGD systems. The sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) The coke burn-off rate ($R_c$) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r(\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r(\%CO/2 + \%CO_2 + \%O_2) + K_3 Q_{oxy}(\%O_{oxy})$$

Where:

$R_c$= Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

$Q_r$= Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

$Q_a$= Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$Q_{oxy}$= Volumetric flow rate of $O_2$ enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$= Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

%CO = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$= $O_2$ concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%O_{oxy}$= $O_2$ concentration in $O_2$ enriched air stream inlet to the fluid catalytic cracking unit regenerator, percent by volume (dry basis).

$K_1$= Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

$K_2$= Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)].

$K_3$= Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate ($Q_r$).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine $CO_2$, CO, and $O_2$ concentrations.

(4) Method 9 and the procedures of §60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in §60.102(b) as follows:

(1) The allowable emission rate ($E_s$) of PM shall be computed for each run using the following equation:

$$E_s = F + A\ (H/R_c)$$

Where:

$E_s$= Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F=Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, $7.5 \times 10^{-4}$kg/million J (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, million J/hr (million Btu/hr).

$R_c$= Coke burn-off rate, Mg coke/hr (ton coke/hr).

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate ($R_c$).

(d) The owner or operator shall determine compliance with the CO standard in §60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e)(1) The owner or operator shall determine compliance with the $H_2S$ standard in §60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the $H_2S$ concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line.

(i) For Method 11, the sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may

result in depletion of the collection solution, although fuel gases containing low concentrations of $H_2S$ may necessitate sampling for longer periods of time.

(ii) For Method 15 or 16, at least three injects over a 1-hour period shall constitute a run.

(iii) For Method 15A, a 1-hour sample shall constitute a run.

(2) Where emissions are monitored by §60.105(a)(3), compliance with §60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6. A 1-hour sample shall constitute a run. Method 6 samples shall be taken at a rate of approximately 2 liters/min. The ppm correction factor (Method 6) and the sampling location in paragraph (f)(1) of this section apply. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C.

(f) The owner or operator shall determine compliance with the $SO_2$ and the $H_2S$ and reduced sulfur standards in §60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the $SO_2$ concentration. The concentration in mg/dscm obtained by Method 6 or 6C is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 $m^2$ (53.8 $ft^2$ ) or at a point no closer to the walls than 1.00 m (39.4 in.) if the cross-sectional area is 5.00 $m^2$ or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. For Method 6C, a run shall consist of the arithmetic average of four 1-hour samples. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6 or 6C. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and $H_2S$ concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The $SO_2$ equivalent for each run shall be calculated after being corrected for moisture and oxygen as the arithmetic average of the $SO_2$ equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3 or 3A. The samples shall be taken simultaneously with the $SO_2$, reduced sulfur and $H_2S$, or moisture samples. The $SO_2$, reduced sulfur, and $H_2S$ samples shall be corrected to zero percent excess air using the equation in paragraph (h)(6) of this section.

(g) Each performance test conducted for the purpose of determining compliance under §60.104(b) shall consist of all testing performed over a 7-day period using Method 6 or 6C and Method 3 or 3A. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(h) For the purpose of determining compliance with §60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, ppmv) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in §60.13(h). These calculations are made using the emission data collected under §60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$Rso_2=100(Cso_2(i)-Cso_2(o))/Cso_2(i)$

where:

$Rso_2$=7-day average sulfur dioxide emission reduction, percent

$Cso_2(i)$=sulfur dioxide emission concentration determined in §60.106(h)(2) at the inlet to the add-on control device, ppmv

$Cso_2(o)$=sulfur dioxide emission concentration determined in §60.106(h)(2) at the outlet to the add-on control device, ppmv

100=conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 ppmv standard, reported on a dry, $O_2$-free basis, shall be calculated using the procedures outlined in §60.106(h)(1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (h) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$C_{adj}=C_{meas}[20.9_c/(20.9-\%O_2)]$

where:

$C_{adj}$=pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

$C_{meas}$=pollutant concentration measured on a dry basis, ppm or g/dscm

$20.9_c$=20.9 percent oxygen−0.0 percent oxygen (defined oxygen correction basis), percent

20.9=oxygen concentration in air, percent

$\%O_2$=oxygen concentration measured on a dry basis, percent

(i) For the purpose of determining compliance with §60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (i)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in §60.106(i)(3) for moisture content and for the concentration of sulfur oxides calculated as sulfur dioxide,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160 °C (320 °F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel $SO_X$ credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (b)(3) of this section, unless paragraph (i)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8–3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide ($Cso_x$).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{so_x} = C_{so_x} Q_{sd} / K$$

Where:

$E_{SOx}$= sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr)

$C_{SOx}$= sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm (gr/dscf)

$Q_{sd}$= dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

K=1,000 g/kg (7,000 gr/lb)

(10) Sulfur oxides emissions calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$R_{SO_x} = \left(E_{SO_x} / R_c\right)$$

Where:

$R_{SOx}$= Sulfur oxides emissions calculated as kg sulfur dioxide per Mg (lb/ton) coke burn-off.

$E_{SOx}$= Sulfur oxides emission rate calculated as sulfur dioxide, kg/hr (lb/hr).

$R_c$= Coke burn-off rate, Mg/hr (ton/hr).

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per Mg (ton) of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with §60.104(b)(2), as provided in §60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(j) For the purpose of determining compliance with §60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129–64, 78, or 95, ASTM D1552–83 or 95, ASTM D2622–87, 94, or 98, or ASTM D1266–87, 91, or 98. (These methods are incorporated by reference: see §60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (j)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^{n} \frac{S_i Q_i}{Q_f}$$

where:

$S_f$= fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

$Q_f$= total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

$S_i$= fresh feed sulfur content expressed in percent by weight of fresh feed for the “ith” sampling location.

$Q_i$= volumetric flow rate of fresh feed stream for the “ith” sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

(k) The test methods used to supplement continuous monitoring system data to meet the minimum data requirements in §60.104(d) will be used as described below or as otherwise approved by the Administrator.

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(3) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

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## § 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.104(b) shall notify the Administrator of the specific provisions of §60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by §60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of §60.104(b), then the Administrator shall be notified by the owner or operator in the report described in paragraph (c) of this section.

(b) Each owner or operator subject to §60.104(b) shall record and maintain the following information:

(1) If subject to §60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to §60.105(a)(13) and §60.106(k)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to §60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if §60.106(i)(12) applies.

(3) If subject to §60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to §60.104(b) shall submit a report except as provided by paragraph (d) of this section. The following information shall be contained in the report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, $O_2$-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under §60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under §60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under §60.106(h);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with §60.104(b)(2) exceeds 9.8 kg $SO_X$ per 1,000 kg coke burn-off, as measured by the daily testing prescribed under §60.106(i). The average emission rate shall be determined using the procedures specified under §60.106(i); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with §60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under §60.106(j).

(2) Any 30-day period in which the minimum data requirements specified in §60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

(iv) A description of the corrective action taken, if any.

(4) If subject to §60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to §60.104(b)(2), for each day in which a Method 8 sample result required by §60.106(i) was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to §60.104(b)(3), for each 8-hour period in which a feed sulfur measurement required by §60.106(j) was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1), if an owner or operator determines that one of the exemptions listed in §60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in §60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(f) The owner or operator of an affected facility shall submit the reports required under this subpart to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(g) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

[54 FR 34029, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7465, Feb. 12, 1999; 65 FR 61755, Oct. 17, 2000; 73 FR 35867, June 24, 2008]

## § 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in §60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under §60.104(b). Performance tests conducted for the purpose of determining compliance under §60.104(b) shall be conducted according to the applicable procedures specified under §60.106.

(b) Owners or operators who seek to comply with §60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with §60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under §60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to §60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under §60.106. In the event that a sample collected under §60.106(i) or (j) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to §60.104(b) who has demonstrated compliance with one of the provisions of §60.104(b) but a later date seeks to comply with another of the provisions of §60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of §60.104(b). The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by §60.107(f).

[54 FR 34030, Aug. 17, 1989, as amended at 55 FR 40178, Oct. 2, 1990; 64 FR 7466, Feb. 12, 1999; 73 FR 35867, June 24, 2008]

## § 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

(1) Section 60.105(a)(13)(iii),

(2) Section 60.106(i)(12).

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment I
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978**

**§ 60.110 Applicability and designation of affected facility.**

(a) Except as provided in §60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151, 416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

**§ 60.111 Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396–78, 89, 90, 92, 96, or 98, gas turbine fuel oils Nos. 2–GT through 4–GT as specified in ASTM D2880–78 or 96, or diesel fuel oils Nos. 2–D and 4–D as specified in ASTM D975–78, 96, or 98a. (These three methods are incorporated by reference—see §60.17.)

(c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) *Hydrocarbon* means any organic compound consisting predominantly of carbon and hydrogen.

(f) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

(h) *Drilling and production facility* means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.

(i) *True vapor pressure* means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from External Floating-Roof Tanks, Second Edition, February 1980 (incorporated by reference—see §60.17).

(j) *Floating roof* means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) *Vapor recovery system* means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) *Reid vapor pressure* is the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 39 FR 20794, June 14, 1974; 45 FR 23379, Apr. 4, 1980; 48 FR 3737, Jan. 27, 1983; 52 FR 11429, Apr. 8, 1987; 65 FR 61755, Oct. 17, 2000]

## § 60.112 Standard for volatile organic compounds (VOC).

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 45 FR 23379, Apr. 4, 1980]

## § 60.113 Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of §60.112.

[45 FR 23379, Apr. 4, 1980]

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment J
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006**

**Source:** 72 FR 64896, Nov. 16, 2007, unless otherwise noted.

**§ 60.590a Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.

(e) *Stay of standards.* Owners or operators are not required to comply with the definition of “process unit” in §60.590 of this subpart until the EPA takes final action to require compliance and publishes a document in theFederal Register.While the definition of “process unit” is stayed, owners or operators should use the following definition:

*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

[49 FR 22606, May 30, 1984, as amended at 73 FR 31376, June 2, 2008]

## § 60.591a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A of part 60, or in subpart VVa of this part, and the following terms shall have the specific meanings given them.

*Alaskan North Slope* means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

*Asphalt* (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.

*Equipment* means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

*In hydrogen service* means that a compressor contains a process fluid that meets the conditions specified in §60.593a(b).

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in §60.593a(c).

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

**Effective Date Note:** At 73 FR 31376, June 2, 2008, §60.591a, the definition of “process unit” was stayed until further notice.

## § 60.592a Standards.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§60.482–1a to 60.482–10a as soon as practicable, but no later than 180 days after initial startup.

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in §60.482–7a.

(1) Comply with §60.483–1a.

(2) Comply with §60.483–2a.

(3) Comply with the Phase III provisions in §63.168, except an owner or operator may elect to follow the provisions in §60.482–7a(f) instead of §63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.484a.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §60.485a except as provided in §60.593a.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§60.486a and 60.487a.

## § 60.593a Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Compressors in hydrogen service are exempt from the requirements of §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) 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. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482–3a(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §60.482–3a(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to §60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in §60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §§60.482–2a and 60.482–7a.

(f) Open-ended valves or lines containing asphalt as defined in §60.591a are exempt from the requirements of §60.482–6a(a) through (c).

(g) Connectors in gas/vapor or light liquid service are exempt from the requirements in §60.482–11a, provided the owner or operator complies with §60.482–8a for all connectors, not just those in heavy liquid service.

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment K
## for a
## Part 70 Operating Permit

### Source Background and Description

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

### Subpart FF—National Emission Standard for Benzene Waste Operations

**Source:** 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

### § 61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in §61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

## § 61.341 Definitions.

*Benzene concentration* means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in §61.355 of this subpart.

*Car-seal* means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

*Chemical manufacturing plant* means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alklylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

*Closed-vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

*Coke by-product recovery plant* means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

*Container* means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

*Control device* means an enclosed combustion device, vapor recovery system, or flare.

*Cover* means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

*External floating roof* means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

*Facility* means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

*Fixed roof* means a cover that is mounted on a waste management unit in a stationary manner and that does not move with fluctuations in liquid level.

*Floating roof* means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

*Flow indicator* means a device which indicates whether gas flow is present in a line or vent system.

*Fuel gas system* means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas

turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

*Individual drain system* means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

*Internal floating roof* means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

*Liquid-mounted seal* means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

*Loading* means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

*Maximum organic vapor pressure* means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

(1) In accordance with §60.17(c); or

(2) As obtained from standard reference texts; or

(3) In accordance with §60.17(a)(37); or

(4) Any other method approved by the Administrator.

*No detectable emissions* means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in §61.355(h) of this subpart.

*Oil-water separator* means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator incude an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Point of waste generation* means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

*Process unit* means equipment assembled and connected by pipes or ducts to produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

*Process unit turnaround* means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by restarting of the process.

*Process unit turnaround waste* means a waste that is generated as a result of a process unit turnaround.

*Process wastewater* means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

*Process wastewater stream* means a waste stream that contains only process wastewater.

*Product tank* means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

*Product tank drawdown* means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

*Safety device* means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

*Segregated stormwater sewer system* means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

*Sewer line* means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

*Slop oil* means the floating oil and solids that accumulate on the surface of an oil-water separator.

*Sour water stream* means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

*Sour water stripper* means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

*Surface impoundment* means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

*Tank* means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

*Treatment process* means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with §61.348 of this subpart.

*Vapor-mounted seal* means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

*Waste* means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

*Waste management unit* means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

*Waste stream* means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

*Wastewater treatment system* means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

*Water seal controls* means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

## § 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in §61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under §61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under §61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under §61.10(b)(3) that is an enforceable commitment to obtain environmental benefits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in §61.348 of this subpart.

(ii) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in §61.355(c)(2) or §61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in §61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in §61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in §61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with §61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in §61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§61.342 through 61.352 of this subpart may be granted by the Administrator as provided in §61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

### § 61.343 Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in §61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with §61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of thefollowing conditions:

( *1* ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( *2* ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

( *3* ) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 $m^3$ (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 $m^3$ (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in §61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of §61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

## § 61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( *1* ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( *2* ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart; and

( *3* ) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

## § 61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in section 5 of the “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of §61.349.

(C) For a container cover, the cover and all openings ( *e.g.,* doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in §61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

## § 61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detactable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( *1* ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( *2* ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

( *3* ) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with §61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in §61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

## § 61.347 Standards: Oil-water separators.

(a) Except as provided in §61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( *1* ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( *2* ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

( *3* ) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

## § 61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with §61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to §61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with §61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in §61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The

benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in §61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in §61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of §61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401–464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of §61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in §61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in §61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

## § 61.349 Standards: Closed-ventsystems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in §61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

( *1* ) The critical operating parameters that affect the emission control performance of the device;

( *2* ) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

( *3* ) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subiect to paragraph (a)(2)(iv) of this section meets the requirements of §61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not

meet the requirements of §61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in §61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in §61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in §61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visable defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in §61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with §61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

## § 61.350 Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

## § 61.351 Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in §61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of §61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

## § 61.352 Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in §61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693–2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in §61.347 of this subpart applicable to the same facilities.

## § 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§61.342 through 61.349, the Administrator will publish in theFederal Registera notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

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

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

## § 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with §61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with §61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in §61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of §61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of §61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in §61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in §61.355(c)(3).

(c) An owner or operator subject to the requirements in §61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW ($150 \times 10^6$ BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW ($150 \times 10^6$ BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being

monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of §61.349(a)(2)(iv), devices to monitor the parameters as specified in §61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under §61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by §61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

## § 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in §61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of §61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of §61.356 and reporting requirements of §61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of §61.356 and reporting requirements of §61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in

paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of §61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in §61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under §61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average ben- zene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of §61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

( *1* ) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

( *2* ) The ammonia still meets the definition of a sour water stripper in §61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW–846 (incorporation by reference as specified in §61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:

C=Flow-weighted annual average benzene concentration for waste stream, ppmw.

$Q_t$=Total annual waste quantity for waste stream, kg/yr (lb/yr).

n=Number of waste samples (at least 3).

$Q_i$=Annual waste quantity for waste stream represented by $C_i$, kg/yr (lb/yr).

$C_i$=Measured concentration of benzene in waste sample i, ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process ($E_b$) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[ \sum_{i=1}^{n} V_i C_i \right]$$

Where:

$E_b$= Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m$^3$ (lb/ft$^3$ ).

$V_i$= Average volume flow rate of waste entering the treatment process during each run i, m$^3$ /hr (ft$^3$ /hr).

$C_i$= Average concentration of benzene in the waste stream entering the treatment process during each run i, ppmw.

n = Number of runs.

$10^6$ = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process ($E_a$) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:

$E_a$= Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m$^3$ (lb/ft$^3$ ).

$V_i$= Average volume flow rate of waste exiting the treatment process during each run i, m$^3$ /hr (ft$^3$ /hr).

$C_i$= Average concentration of benzene in the waste stream exiting the treatment process during each run i, ppmw.

n = Number of runs.

$10^6$ = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with §61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6}\left[\sum_{i=1}^{n} V_i C_i\right]$$

Where:

$E_b$= Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

K = Density of the waste stream, kg/m$^3$ (lb/ft$^3$ ).

$V_i$= Average volume flow rate of waste entering the combustion unit during each run i, m$^3$ /hr (ft$^3$ /hr).

$C_i$= Average concentration of benzene in the waste stream entering the combustion unit during each run i, ppmw.

n = Number of runs.

$10^6$ = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b VC\left(10^{-6}\right)$$

Where:

$M_i$= Mass of benzene emitted during run i, kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, $m^3$ ($ft^3$ ).

C = Concentration of benzene measured in the exhaust, ppmv.

$D_b$= Density of benzene, 3.24 $kg/m^3$ (0.202 $lb/ft^3$ ).

$10^6$ = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left( \sum_{i=1}^{n} M_i \right) / T$$

Where:

$E_a$= Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

$M_i$= Mass of benzene emitted from the combustion unit during run i, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

$E_b$= Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

$E_a$= Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with §61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§61.343 through 61.347, and §61.349 of this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

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

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under §61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6}\left(\sum_{i=1}^{n} C_{ai} MW_i\right)$$

$$M_{bj} = \frac{K_1 V_{bj}}{10^6}\left(\sum_{i=1}^{n} C_{bi} MW_i\right)$$

$M_{aj}$= Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

$M_{bj}$= Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

$V_{aj}$= Volume of vent stream entering the control device during run j, at standard conditions, $m^3$ ($ft^3$ ).

$V_{bj}$= Volume of vent stream exiting the control device during run j, at standard conditions, $m^3$ ($ft^3$ ).

$C_{ai}$= Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

$C_{bi}$= Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

$MW_i$= Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

$K_1$= Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/$m^3$ (0.00118 lb-mol/$ft^3$ )

$10^{-6}$=Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a - \left(\sum_{j=1}^{n} M_{aj}\right) / T$$

$$E_b - \left(\sum_{j=1}^{n} M_{bj}\right) / T$$

Where:

$E_a$= Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

$E_b$= Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

$M_{aj}$= Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

$M_{bj}$= Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

$E_b$= Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

$E_a$= Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with §61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not

annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by §61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with §61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in §61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by §61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by §61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by §61.342(e)(2).

(iv) Submit in the annual report required under §61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

## § 61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(2) For each waste stream exempt from §61.342(c)(1) in accordance with §61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with §61.342(c)(3)(i), or

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with §61.342(c)(3)(ii).

(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with §61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with §61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with §61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with §61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with §61.355(a)(1)(iii) of this section.

(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with §61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with §61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with §61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with §61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with §61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.

(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.

(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition,

constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device subject to the requirements of §61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under §61.349 (a)(2)(iv).

(ii) [Reserved]

(3) If performance tests are used to determine control device performance in accordance with §61.349(c) of this subpart:

(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.

(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.

(iv) All test results.

(g) An owner or operator shall maintain a record for each visual inspection required by §§61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§61.343 through 61.347 and §61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with §61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with §61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with §61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters ) to be monitored to ensure that the unit will be operated in conformance with these standards

and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(4) If measurements of waste stream benzene concentration are performed in accordance with §61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters ) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under §61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.

(ii) The flow monitoring devices required under §61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(4) If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature.

(5) If a catalytic vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.

(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by §61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of §61.354(c)(5).

(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.

(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with §61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of

benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in §61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of §61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693–2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693–2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in §61.343 or the control requirements for containers in §61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

## § 61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to §61.342 and is determined by the procedures specified in §61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with §61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in §61.10(a).

(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the

information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under §61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under §61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(3) If an owner or operator elects to comply with the requirements of §61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.

(4) If an owner or operator elects to comply with the alternative requirements of §61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:

(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;

(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(5) If an owner or operator elects to comply with the alternative requirements of §61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the applicable location described in §61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with §61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.

(iv) For a control device monitored in accordance with §61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

(A) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference.

(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), as mesured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(F) Each period in which the pilot flame of a flare is absent.

(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by §61.349(a)(2)(i)(C) of this subpart.

(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in §61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in §61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of §61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with §61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that summarizes all inspections required by §§61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzone emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under §61.07 or §61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in §61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693–2(a), that are outside the prescribed limits.

[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

## § 61.358 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Alternative means of emission limitation under §61.353 of this subpart will not be delegated to States.

# Indiana Department of Environmental Management
# Office of Air Quality

## Attachment L
## for a
## Part 70 Operating Permit

**Source Background and Description**

| | |
|---|---|
| **Source Name:** | Countrymark Cooperative, LLP |
| **Source Location:** | 1200 Refinery Road, Mount Vernon, Indiana |
| **County:** | Posey |
| **SIC Code:** | 2911 |
| **Permit Renewal No.:** | T129-25424-00003 |
| **Permit Reviewer:** | RLO |

**Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**

**Source:** 73 FR 35867, June 24, 2008, unless otherwise noted.

**§ 60.100a Applicability, designation of affected facility, and reconstruction.**

Link to an amendment published at 73 FR 78552, Dec. 22, 2008.

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Except for flares, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which commence construction, modification, or reconstruction after May 14, 2007. For flares, the provisions of this subpart apply only to flares which commence construction, modification, or reconstruction, after June 24, 2008.

(c) For the purposes of this subpart, under §60.14, a modification to a flare occurs if:

(1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting); or

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) For purposes of this subpart, under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following May 14, 2007. 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.

**Effective Date Note:** At 73 FR 78548, Dec. 22, 2008, §60.100a(c) was stayed until Feb. 24, 2009.

## § 60.101a Definitions.

Link to an amendment published at 73 FR 78552, Dec. 22, 2008.

Terms used in this subpart are defined in the Clean Air Act, in §60.2, and in this section.

*Coke burn-off* means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.104a.

*Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

*Delayed coking unit* means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.

*Flare* means an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems.

*Flexicoking unit* means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

*Fluid catalytic cracking* unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

*Fluid coking unit* means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

*Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners, but does include gases from flexicoking unit gasifiers. *Fuel gas* does not include vapors that are collected and combusted to comply with the wastewater provisions in §60.692, 40 CFR 61.343 through 61.348, 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

*Fuel gas combustion device* means any equipment, such as process heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

*Fuel gas system* means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

*Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide ($SO_2$) and recycling the $SO_2$to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the $SO_2$to a sulfur product.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Process heater* means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

*Process upset gas* means any gas generated by a petroleum refinery process unit as a result of upset or malfunction.

*Reduced sulfur compounds* means hydrogen sulfide ($H_2S$), carbonyl sulfide, and carbon disulfide.

*Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to $H_2S$ and either recycling the $H_2S$ to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the $H_2S$ to a sulfur product.

*Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

*Sulfur pit* means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

*Sulfur recovery plant* means all process units which recover sulfur from $HS_2$and/or $SO_2$at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. Sulfur recovery plants that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

**Effective Date Note:** At 73 FR 78548, Dec. 22, 2008, in §60.101a, the definition of “flare” was stayed until Feb. 24, 2009.

## § 60.102a Emissions limitations.

Link to an amendment published at 73 FR 78552, Dec. 22, 2008.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (h) of this section on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg)(1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides ($NO_X$) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide ($SO_2$) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to §60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in §60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under §60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen ($O_2$) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average $O_2$concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide ($SO_2$) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide ($HS_2$), each calculated as ppm $SO_2$by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times \left(-0.038 * (\%O_2)^2 + 11.53 * \%O_2 + 25.6\right) \qquad \text{(Eq. 1)}$$

Where:

$E_{LS}$= Emission rate of $SO_2$for large sulfur recovery plant, ppmv;

$k_1$= Constant factor for emission limit conversion: $k_1$= 1 for converting to $SO_2$limit and $k_1$= 1.2 for converting to the reduced sulfur compounds limit; and

$\%O_2$= $O_2$concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis) of $SO_2$at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 3,000

ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide ($H_2S$), each calculated as ppm SO2by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{ss} = k_1 \times \left(-0.38 * (\%O_2)^2 + 115.3 * \%O_2 + 256\right) \qquad \text{(Eq. 2)}$$

Where:

$E_{SS}$= Emission rate of $SO_2$for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emission limits in paragraphs (g)(1) through (3) of this section.

(1) For each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain $SO_2$in excess of 20 ppmv (dry basis, corrected to 0 percent excess air) determined hourly on a 3-hour rolling average basis and $SO_2$in excess of 8 ppmv (dry basis, corrected to 0 percent excess air), determined daily on a 365 successive day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains $H_2S$ in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and $H_2S$ in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr), the owner or operator shall not discharge to the atmosphere any emissions of $NO_X$in excess of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

(3) Except as provided in paragraphs (h) and (i) of this section, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day ($m^3$ /day) (250,000 standard cubic feet per day (scfd)) on a 30-day rolling average. The owner or operator of a newly constructed or reconstructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart.

(h) The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from paragraph (g) of this section.

(i) In periods of fuel gas imbalance that are described in the flare management plan required in section 60.103a(a), compliance with the emission limit in paragraph (g)(3) of this section is demonstrated by following the procedures and maintaining records described in the flare management plan to document the periods of excess fuel gas.

**Effective Date Note:** At 73 FR 78548, Dec. 22, 2008, §60.102a(g) was stayed until Feb 24, 2008.

## § 60.103a Work practice standards.

(a) Each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan. The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 1 year after the flare becomes an affected flare subject to this subpart. The plan must include:

(1) A diagram illustrating all connections to the flare;

(2) Methods for monitoring flow rate to the flare, including 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 for flare gas monitoring devices;

(3) Procedures to minimize discharges to the flare gas system during the planned start-up and shutdown of the refinery process units that are connected to the affected flare;

(4) Procedures to conduct a root cause analysis of any process upset or malfunction that causes a discharge to the flare in excess of 14,160 $m^3$ /day (500,000 scfd);

(5) Procedures to reduce flaring in cases of fuel gas imbalance (i.e., excess fuel gas for the refinery's energy needs); and

(6) Explanation of procedures to follow during times that the flare must exceed the limit in §60.102a(g)(3) (e.g., keep records of natural gas purchases to support assertion that the refinery is producing more fuel gas than needed to operate the processes).

(b) Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of SO2. For any root cause analysis performed, the owner or operator shall record the identification of the affected facility, the date and duration of the discharge, the results of the root cause analysis, and the action taken as a result of the root cause analysis. The first root cause analysis for a modified flare must be conducted no later than the first discharge that occurs after the flare has been an affected flare subject to this subpart for 1 year.

(c) Each owner or operator of a delayed coking unit shall depressure to 5 lb per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device.

## § 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in §60.102a according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in §60.105a(b), to use bag leak detectors according to the requirements in §60.105a(c), or to use COMS according to the requirements in §60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A–1 through A–8 or other methods as specified in this section, except as provided in §60.8(b).

(d) The owner or operator shall determine compliance with the PM, NOX, SO2, and CO emissions limits in §60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(4) Method 5, 5B, or 5F of appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in §63.102a(b)(1). Use Method 5 or 5B of appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in §63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM ($E_{PM}$) is computed for each run using Equation 3 of this section:

$$E = \frac{c_s \, Q_{sd}}{K \, R_c} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of PM, g/kg, lbs per 1,000 lbs (lb/1,000 lbs) of coke burn-off;

cs= Concentration of total PM, grams per dry standard cubic meter (g/dscm), gr/dscf;

Qsd= Volumetric flow rate of effluent gas, dry standard cubic meters per hour, dry standard cubic feet per hour;

Rc= Coke burn-off rate, kilograms per hour (kg/hr), lbs per hour (lbs/hr) coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (Rc) is computed for each run using Equation 4 of this section:

$$R_c = K_1 Q_r \left(\%CO_2 + \%CO\right) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2\right) + K_3 Q_{oxy} \left(\%O_{oxy}\right) \qquad \text{(Eq. 4)}$$

Where:

Rc= Coke burn-off rate, kg/hr (lb/hr);

Qr= Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min), dry standard cubic feet per minute (dscf/min);

Qa= Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Qoxy= Volumetric flow rate of $O_2$enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

%CO2= Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%$O_2$= O2concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%Ooxy= O2concentration in O2enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K1= Material balance and conversion factor, 0.2982 (kg-min)/(hr-dsc-%) [0.0186 (lb-min)/(hr-dscf-%)];

K2= Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K3= Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Qr) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A–1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Qris calculated using average exhaust gas concentrations as measured by the monitors in §60.105a(b)(2), if applicable, using Equation 5 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 5)}$$

Where:

Qr= Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Qa= Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Qoxy= Volumetric flow rate of O2enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

%CO2= Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with §60.105a(g)(3), assume %CO to be zero;

%O2= O2concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$= O2concentration in O2enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A–4 to part 60 for moisture content and for the concentration of SO2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for moisture content and for the concentration of NOXcalculated as nitrogen dioxide (NO2); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(7) Method 10, 10A, or 10B of appendix A–4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NOX, SO2, and CO pollutant concentrations to 0 percent excess air or 0 percent O2using Equation 6 of this section:

$$C_{adj} = C_{meas}\left[{20.9_c}\Big/{(20.9 - \%O_2)}\right] \qquad \text{(Eq. 6)}$$

Where:

Cadj= pollutant concentration adjusted to 0 percent excess air or O2, parts per million (ppm) or g/dscm;

Cmeas= pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9c= 20.9 percent O2–0.0 percent O2(defined O2correction basis), percent;

20.9 = O2concentration in air, percent; and

%O2= O2concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM limit in §60.102a(b)(1) and elects to comply with the COMS alternative monitoring option in §60.105a(d) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 7 of this section:

$$Opacity\ Limit = Opacity_{st}\, x \left( \frac{1 lb/1,000\, lb\ coke\ burn}{PMEmR_{st}} \right) \qquad (Eq.\ 7)$$

Where:

Opacity limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

Opacityst= Hourly average opacity measured during the source test runs, percent; and

PMEmRst= PM emission rate measured during the source test, lb/1,000 lbs coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to §60.105a(h)(3) and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O2concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O2concentrations as the average of the average temperature and O2concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO2and H2S emissions limits for sulfur recovery plants in §§60.102a(f)(1)(i), 60.102a(f)(1)(iii), 60.102a(f)(1)(iii), 60.102a(f)(2)(i), and 60.102a(f)(2)(iii) and the reduced sulfur compounds and H2S emissions limits for sulfur recovery plants in §60.102a(f)(1)(ii) and §60.102a(f)(2)(ii) using the following methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(4) Method 6, 6A, or 6C of appendix A–4 to part 60 to determine the SO2concentration. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(5) Method 15 or 15A of appendix A–5 to part 60 or Method 16 of appendix A–6 to part 60 to determine the reduced sulfur compounds and H2S concentrations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H2S concentration after correcting for moisture and O2as the arithmetic average of the H2S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO2equivalent for each run after correcting for moisture and O2as the arithmetic average of the SO2equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 6 of this section to adjust pollutant concentrations to 0 percent O2or 0 percent excess air.

(i) The owner or operator shall determine compliance with the SO2and NOXemissions limits in §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60;

(4) Method 6, 6A, or 6C of appendix A–4 to part 60 to determine the $SO_2$concentration. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under §60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for moisture content and for the concentration of NOXcalculated as NO2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(j) The owner or operator shall determine compliance with the H2S emissions limit in §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60;

(4) Method 11, 15, or 15A of appendix A–5 to part 60 or Method 16 of appendix A–6 to part 60 for determining the $H_2S$ concentration for affected plants using an $H_2S$ monitor as specified in §60.107a(a)(2). The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or for each individual fuel gas stream used in the fuel gas combustion device.

(i) For Method 11 of appendix A–5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H2S may necessitate sampling for longer periods of time.

(ii) For Method 15 of appendix A–5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A–5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under §60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

## § 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

(a) *FCCU and FCU subject to PM emissions limit* . Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in §60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters* . Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in §60.102a(b)(1) shall comply with the requirements in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the requirements in paragraph (b)(1)(i) through (iii) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary voltage to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alterative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in §60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of $CO_2$, $O_2$(dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.

(i) The owner or operator shall install, operate, and maintain each monitor according to Performance Specification 3 of appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each $CO_2$, $O_2$, and CO monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Method 3 of appendix A–3 to part 60 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to part 60, including quarterly accuracy determinations for $CO_2$and CO monitors, annual accuracy determinations for $O_2$monitors, and daily calibration drift tests.

(c) *Bag leak detection systems* . Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS)* . An owner or operator subject to the PM concentration emission limit (in gr/dscf) in §60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an $O_2$monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in §60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or

operator shall use EPA Methods 5 or 5I of appendix A–3 to part 60 or Method 17 of appendix A–6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60. The span value of this $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each $O_2$monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each $O_2$monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS* . Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in §60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to §60.13(c) and Performance Specification 1 of appendix B to part 60.

(f) *FCCU and FCU subject to NO* X *limit* . Each owner or operator subject to the $NO_X$emissions limit in §60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of $NO_X$emissions into the atmosphere. The monitor must include an $O_2$monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $NO_X$monitor according to Performance Specification 2 of appendix B to part 60. The span value of this $NO_X$monitor is 200 ppmv $NO_X$.

(2) The owner or operator shall conduct performance evaluations of each $NO_X$monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60. The span value of this $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each $NO_X$and $O_2$monitor, including quarterly accuracy determinations for $NO_X$monitors, annual accuracy determinations for $O_2$monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO* 2 *limit* . The owner or operator subject to the $SO_2$emissions limit in §60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of $SO_2$emissions into the atmosphere. The monitor shall include an $O_2$monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $SO_2$monitor according to Performance Specification 2 of appendix B to part 60. The span value of this $SO_2$monitor is 200 ppmv $SO_2$.

(2) The owner or operator shall conduct performance evaluations of each $SO_2$monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60. The span value of this $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each $SO_2$and $O_2$monitor, including quarterly accuracy determinations for $SO_2$monitors, annual accuracy determinations for $O_2$monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit* . Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in §60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to part 60. The span value for this instrument is 1,000 ppm CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A–4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to part 60. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 of

appendix A–4 to part 60 and employ the sample conditioning system of Method 10A of appendix A–4 to part 60, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to part 60 may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and $O_2$monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and $O_2$concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and $O_2$concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions* . For the purpose of reports required by §60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in §60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, *e.g.* , determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to §60.105a(b)(1), all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under §60.105a(b)(1), fall below the levels established during the performance test.

(2) If a PM CEMS is used according to §60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under §60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(3) If a COMS is used according to §60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under §60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(4) All rolling 7-day periods during which the average concentration of $NO_X$as measured by the $NO_X$CEMS under §60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(5) Except as provided in paragraph (i)(7) of this section, all rolling 7-day periods during which the average concentration of $SO_2$as measured by the $SO_2$CEMS under §60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of $SO_2$as measured by the $SO_2$CEMS exceeds 25 ppmv.

(6) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §1A60.105a(h) exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and $O_2$concentration as measured by the continuous monitoring systems under §60.105a(h)(4) fall below the operating limits established during the performance test.

## § 60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in §60.102a(f)(1) or §60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the $SO_2$emission limit in §60.102a(f)(1)(i) or §60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any $SO_2$emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are two times the applicable $SO_2$emission limit and between 10 and 25 percent $O_2$, inclusive.

(ii) The owner or operator shall install, operate, and maintain each $SO_2$CEMS according to Performance Specification 2 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each $SO_2$monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6 or 6C of appendix A–4 to part 60 and Method 3 or 3A of appendix A–2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6.

(2) For sulfur recovery plants that are subject to the reduced sulfur compound and $H_2S$ emission limit in §60.102a(f)(1)(ii) or §60.102a(f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur, $H_2S$, and $O_2$emissions into the atmosphere. The reduced sulfur emissions shall be calculated as $SO_2$(dry basis, zero percent excess air).

(i) The span values for this monitor are two times the applicable reduced sulfur emission limit, two times the $H_2S$ emission limit, and between 10 and 25 percent $O_2$, inclusive.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each $H_2S$ CEMS according to Performance Specification 7 of appendix B to part 60.

(v) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 11, 15, or 15A of appendix A–5 to part 60 or Method 16 of appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(vi) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60.

(vii) The span value for the $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(viii) The owner or operator shall conduct performance evaluations for the $O_2$monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(ix) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each $O_2$monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur monitor required in paragraph (a)(2) of this section, the owner or operator shall install, calibrate, operate, and maintain an instrument using an air or $O_2$dilution and oxidation system to convert any reduced sulfur to $SO_2$for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant $SO_2$. The monitor must include an $O_2$monitor for correcting the data for excess $O_2$.

(i) The span value for this monitor is two times the applicable $SO_2$emission limit.

(ii) The owner or operator shall conduct performance evaluations of each $SO_2$monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the $O_2$monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each $SO_2$monitor, annual accuracy determinations for each $O_2$monitor, and daily calibration drift determinations.

(b) *Excess emissions* . For the purpose of reports required by §60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in §60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section.Note:Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods during which the average concentration of $SO_2$as measured by the $SO_2$continuous monitoring system required under paragraph (a)(1) of this section exceeds the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur (as $SO_2$) as measured by the reduced sulfur continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of $H_2S$ as measured by the $H_2S$ continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

## § 60.107a Monitoring of emissions and operations for fuel gas combustion devices.

Link to an amendment published at 73 FR 78552, Dec. 22, 2008.

(a) *Fuel gas combustion devices subject to SO* 2 *or H* 2 *S limit.* The owner or operator of a fuel gas combustion device that is subject to the requirements in §60.102a(g) shall comply with the requirements in paragraph (a)(1) of this section for $SO_2$emissions or paragraph (a)(2) of this section for $H_2S$ emissions.

(1) The owner or operator of a fuel gas combustion device subject to the $SO_2$emissions limits in §60.102a(g)(1)(i) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of $SO_2$emissions into the atmosphere. The monitor must include an $O_2$monitor for correcting the data for excess air.

(i) The owner or operator shall install, operate, and maintain each $SO_2$monitor according to Performance Specification 2 of appendix B to part 60. The span value for the $SO_2$monitor is 50 ppm $SO_2$.

(ii) The owner or operator shall conduct performance evaluations for the $SO_2$monitor according to the requirements of §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A–4 to part 60. Samples taken by Method 6 of appendix A–4 to part 60 shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60. The span value for the $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the $O_2$monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60, including quarterly accuracy determinations for $SO_2$monitors, annual accuracy determinations for $O_2$monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the $SO_2$emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device subject to the $H_2S$ concentration limits in §60.102a(g)(1)(ii) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of $H_2S$ in the fuel gases before being burned in any fuel gas combustion device.

(i) The owner or operator shall install, operate, and maintain each $H_2S$ monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 320 ppmv $H_2S$.

(ii) The owner or operator shall conduct performance evaluations for each $H_2S$ monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A–5 to part 60 or Method 16 of appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each $H_2S$ monitor.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of $H_2S$ in the fuel gas being burned.

(3) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §60.102a(h) and fuel gas streams combusted in a process heater or other fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from H* 2 *S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device may apply for an exemption from the $H_2S$ monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system, and the affected fuel gas combustion device(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high $H_2S$ content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm $H_2S$. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see §60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for $H_2S$; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of $H_2S$ concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting $H_2S$ content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an $H_2S$ test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin $H_2S$ monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour $H_2S$ concentration limit. The owner or operator must determine a rolling 365-day average using the stain sampling results; an average $H_2S$ concentration of 5 ppmv must be used for days prior to the operation change.

(c) *Process heaters subject to NO* X *limit.* The owner or operator of a process heater subject to the $NO_X$emission limit in §60.102a(g)(2) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of $NO_X$emissions into the atmosphere. The monitor must include an $O_2$monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $NO_X$monitor according to Performance Specification 2 of appendix B to part 60. The span value of this $NO_X$monitor is 200 ppmv $NO_X$.

(2) The owner or operator shall conduct performance evaluations of each $NO_X$monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to part 60 for conducting the relative accuracy

evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$monitor according to Performance Specification 3 of appendix B to part 60. The span value of this $O_2$monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each $NO_X$and $O_2$monitor, including quarterly accuracy determinations for $NO_X$monitors, annual accuracy determinations for $O_2$monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with low-$NO_X$burners (LNB) or ultra low-$NO_X$burners (ULNB) is not subject to the monitoring requirements in paragraphs (c)(1) through (5) of this section. The owner or operator of such a process heater must conduct biennial performance tests to demonstrate compliance.

(d) *Sulfur monitoring for affected flares* . The owner or operator of an affected flare subject to §60.103a(b) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur in flare gas. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

(1) The owner or operator shall install, operate, and maintain each reduced sulfur CEMS according to Performance Specification 5 of appendix B to part 60.

(2) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A–5 to part 60.

(3) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each reduced sulfur monitor.

(e) *Flow monitoring for flares* . The owner or operator of an affected flare subject to §60.102a(g)(3) shall install, operate, calibrate, and maintain CPMS to measure and record the exhaust gas flow rate. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

(1) The CPMS must be able to correct for the temperature and pressure of the system and output flow in standard conditions as defined in §60.2.

(2) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(f) *Excess emissions* . For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) are defined as specified in paragraphs (f)(1) through (4) of this section.Note:Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) All rolling 3-hour periods during which the average concentration of $SO_2$as measured by the $SO_2$continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and all rolling 365-day periods during which the average concentration as measured by the $SO_2$continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv; or

(2) All rolling 3-hour periods during which the average concentration of $H_2S$ as measured by the $H_2S$ continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv, all days in which the concentration of $H_2S$ as measured by daily stain tube sampling required under paragraph (b)(3)(iii) of this section exceeds 162 ppmv, and all rolling 365-day periods during which the average concentration as measured by the $H_2S$ continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(3) All rolling 24-hour periods during which the average concentration of $NO_X$as measured by the $NO_X$continuous monitoring system required under paragraph (c) of this section exceeds 40 ppmv.

(4) All rolling 30-day periods during which the average flow rate to an affected flare as measured by the monitoring system required under paragraph (e) of this section exceeds 250,000 scfd.

**Effective Date Note:** At 73 FR 78549, Dec. 22, 2008, §60.107a (d) and (e) were stayed until Feb. 24, 2008.

## § 60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section.

(b) Each owner or operator subject to an emissions limitation in §60.102a shall notify the Administrator of the specific monitoring provisions of §§60.105a, 60.106a, and 60.107a with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by §60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan and each root cause analysis of a discharge;

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in §60.105a(c).

(3) Records of bag leak detection system alarms and actions according to §60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in §60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in §60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in §60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) The owner or operator shall record and maintain records of discharges greater than 500 lb/day $SO_2$from any affected fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scfd. These records shall include:

(i) A description of the discharge.

(ii) For discharges greater than 500 lb/day $SO_2$, the date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices other than flares.

(iv) For discharges greater than 500 lb/day $SO_2$, the measured or estimated concentration of $H_2S$, TRS and $SO_2$of the stream discharged. Process knowledge can be used to make these estimates for fuel gas combustion devices other than flares.

(v) For discharges greater than 500 lb/day $SO_2$, the cumulative quantity of $H_2S$ and $SO_2$released into the atmosphere. For releases controlled by flares, assume 99 percent conversion of reduced sulfur to $SO_2$. For other fuel gas combustion devices, assume 99 percent conversion of $H_2S$ to $SO_2$.

(vi) Results of any root-cause analysis conducted as required in §60.103a(a)(4) and §60.103a(b).

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) A root-cause summary report that provides the information described in paragraph (e)(6) of this section for all discharges for which a root-cause analysis was required by §60.103a(a)(4) and §60.103a(b).

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

## § 60.109a Delegation of authority.

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency, the approval authorities contained in paragraphs (b)(1) through (3) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of a major change to test methods under §60.8(b). A “major change to test method” is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under §60.13(i). A “major change to monitoring” is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under §60.7(b) through (f). A “major change to recordkeeping/reporting” is defined in 40 CFR 63.90.

# Indiana Department of Environmental Management
# Office of Air Quality

Addendum to the
Technical Support Document for a Part 70 Operating Permit Renewal

| | |
|---|---|
| **Source Name:** | **Countrymark Cooperative, LLP** |
| **Source Location:** | **1200 Refinery Road, Mount Vernon, Indiana** |
| **County:** | **Posey** |
| **SIC Code:** | **2911** |
| **Permit Renewal No.:** | **T129-25424-00003** |
| **Permit Reviewer:** | **Roger Osburn** |

On May 6, 2009, the Office of Air Quality (OAQ) had a notice published in the Mount Vernon Democrat, Mount Vernon, Indiana, stating that Countrymark Cooperative, LLP had applied for a Part 70 Operating Permit renewal to continue to operate a petroleum refinery. The notice also stated that OAQ proposed to issue a permit renewal for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

IDEM, OAQ prefers the TSD remain the same as the version that was public noticed. Therefore, the TSD will not be changed, but will be noted in this addendum. Changes to the permit are noted as follows: ~~struck~~ language has been deleted; **bold** language has been added. The Table of Contents has been modified to reflect these changes.

The permit will also incorporate changes made from Administrative Amendment No. 129-28028-00003, issued on June 26, 2009, which was issued after the public notice period for this renewal.

Comments on the proposed Part 70 permit renewal were received on June 5, 2009 from Ms. Pat Sorensen, of Environmental Resources Management, representing Countrymark Cooperative, LLP.

**Comment 1:** Countrymark Cooperative, LLP proposes to update the reference to the stay of Subpart Ja.

**Response 1:** The following changes will be made to the Table of Contents and Condition E.12.2:

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E.12.2 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS [40 CFR Part 60, Subpart Ja (**Certain Sections** Currently Under **Indefinate** Stay ~~Until September 26, 2008~~)]

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**Comment 2:** In Condition E.1.2, Countrymark Cooperative, LLP proposes to indicate that 40 CFR 63, Subpart R is referenced by 40 CFR 63, Subpart CC and add applicable sections of 40 CFR 63, Subpart R.

**Response 2:** The following changes will be made to Condition E.1.2:

***

E.1.2 Gasoline Distribution Facilities NESHAP [326 IAC 20-10-1] [40 CFR 63, Subpart R]

The Permittee shall comply with the provisions of 40 CFR 63, Subpart R - National Emission Standards for Gasoline Distribution Facilities, which are incorporated by reference as 326 IAC 20-10-1, apply to the truck loading rack and flare. This rule is included as Attachment A. This source is subject to the following requirements of 40 CFR Part 63, Subpart R:

(1) 40 CFR Part 63.420
(2) 40 CFR Part 63.421
(3) 40 CFR Part 63.422(a-c)
(4) 40 CFR Part 63.424
(5) 40 CFR Part 63.425(a-c), (e-h)
(6) 40 CFR Part 63.427(a-b)
(7) 40 CFR Part 63.428(b), (c), **(e), (f)**, (g)~~(1)~~, (h)(1-3), **(i), (j), (k)**
(8) Table 1.

**Comment 3:** In Section E.2, Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 63, Subpart UUU.

**Response 3:** The following changes will be made to the Facility Description in Section E.2.

**SECTION E.2 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]:

**(c) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10; Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.**

(s) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74; Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

~~(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122 (constructed in 2005).~~

~~(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 (constructed in 2005).~~

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following:

~~(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1 (to be constructed in 2005).~~

~~(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2 (to be constructed in 2005). In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.~~

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3 (to be constructed in 2005).

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4 (to be constructed in 2005).

Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

~~(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.~~

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

**Comment 4:** The wrong NESHAP title is listed in the heading of Condition E.2.2 and affected facilities should be changed.

**Response 4:** The following changes will be made to Condition E.2.2:

E.2.2 ~~Standards of Performance for Petroleum Refineries~~ **National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units** [40 CFR Part 63, Subpart UUU] [326 IAC 20-50-1]

The Permittee shall comply with the provisions of 40 CFR 63, Subpart UUU - **National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units**, ~~Gasoline Distribution Facilities,~~ which are incorporated by reference as 326 IAC 20-50-1, apply to the ~~truck loading rack and flare~~ **associated process vents and bypass lines**. This rule is included as Attachment B. This source is subject to the following requirements of 40 CFR Part 63, Subpart UUU:

**Comment 5:** In Section E.3, Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 60, Subpart J.

**Response 5:** The following changes will be made to the Facility Description in Section E.3:

**SECTION E.3 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]:

**(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122, constructed in 2005.**

**(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123 constructed in 2005.**

**(ll)**

**(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1, constructed in 2005.**

**(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2, constructed in 2005. In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.**

(oo) One (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131.

Under the Standards of Performance for Petroleum Refineries NSPS (40 CFR 60, Subpart J), the boiler B4, is considered a new source.

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

**Comment 6:** Countrymark Cooperative, LLP proposes to change the applicable sections of 40 CFR 60, Subpart J in Condition E.3.2.

**Response 6:** The following changes will be made to Condition E.3.2:

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(1) 40 CFR 60.100~~(a), (b), (c), (d), (e)~~
(2) 40 CFR 60.101
(3) ~~40 CFR 60.102~~
(4) ~~40 CFR 60.103~~
(5) 40 CFR 60.104**(a)(1)**
(6) 40 CFR 60.105(a)~~(1-2)(i-ii)(3)(i-iv)(4)(i-iv)(A-D)(5)(i-ii)(6)(i-ii)(7)(i-iii)(8)(i-ii)(9)(i-ii)(10)(11)(12)(i-ii)(13)(i-iii), (b)(1)(i-v)(2)(3)(i-iii), (c), (d), (e)(1-4)(i-ii)~~**(b), (e)(3)**
(7) 40 CFR 60.106(a), ~~(b)(1-3)(i-ii)(4), (c)(1-3), (d),~~ (e)(1)(i-iii)~~(2), (f)(1-3), (g), (h)(1-6), (i)(1-12), (j)(1-3)(i-iii)(4)(k)(1-4)~~
(8) 40 CFR 60.107~~(a), (b)(1)(i-iii)(2-4), (c)(1)(i-iii)(2-3)(i-iv)(4)(i-vi)(5-6), (d-g),~~ **(e), (f), (g)**
(9) 40 CFR 60.108(a~~-e~~)
(10) 40 CFR 60.109~~(a), (b)(1-2)~~

**Comment 7:** Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 60, Subpart GGG, in Section E.6.

**Response 7:** The following changes will be made to Section E.6:

**SECTION E.6 FACILITY OPERATION CONDITIONS**
**Facility Description [326 IAC 2-7-5(15)]:**

**The following equipment in VOC service.**

(v) Pipeline Valves - Gas, identified as 090; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091; Under 40 CFR 60, Subpart GGG, valves are

considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093; Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094; Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095; Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097; Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099; Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(gg) Vessel Relief Valves, identified as 101; Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, **each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector** ~~equipment associated with the sampling connection system~~ is considered an affected source at a petroleum refinery.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, ~~equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.~~ **each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector is considered an affected source at a petroleum refinery.**

(1) pipeline Valves - Gas, identified as 090.
(2) pipeline Valves - Light Liquid, identified as 091.
(3) pipeline Valves - Heavy Liquid, identified as 092.
(4) pipeline Valves - Hydrogen, identified as 093.
(5) open Ended Valves, identified as 094.
(6) ~~Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073.~~
(7) flanges, identified as 095.
(8) pump Seals Light Liquid, identified as 096.
(9) pump Seals Heavy Liquid, identified as 097.
(10) compressor Seals - Gas, identified as 098.
(11) compressor Seals - Heavy Liquid, identified as 099.
(12) ~~drains, identified as 100.~~
(13) vessel Relief Valves, identified as 101.
(14) ~~cooling Towers, identified as 119.~~

**Comment 8:** Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 63, Subpart CC, in Section E.8.

**Response 8:** The following changes will be made to Section E.8:

**SECTION E.8 FACILITY OPERATION CONDITIONS**

**Facility Description [326 IAC 2-7-5(15)]**

~~(pp) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:~~

~~(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.~~

~~Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.~~

~~(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.~~

~~(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.~~

~~Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.~~

~~Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.~~

~~Under 40 CFR 60, Subpart GGG, valves are considered affected facilities at a petroleum refinery.~~

~~Under 40 CFR 61 Subpart FF new and existing drains are considered affected facilities for benzene waste operations.~~

~~(d) One (1) fixed roof cone tank, identified as 22A, with a maximum capacity of 1,050,000 gallons, constructed in 2003.~~

**(1) All miscellaneous process vents from petroleum refining process units;**

**(2) All storage vessels associated with petroleum refining process units;**

**(3) All wastewater streams and treatment operations associated with petroleum refining process units;**

**(4) All equipment leaks from petroleum refining process units;**

**(5) All gasoline loading racks classified under Standard Industrial Classification code 2911;**

**(6) All marine vessel loading operations located at a petroleum refinery; and**

**(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.**

**Comment 9:** Countrymark Cooperative, LLP proposes to change the applicable sections of 40 CFR 63, Subpart CC.

**Response 9:** The following changes will be made to Condition E.8.2:

E.8.2 National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries [326 IAC 20-16-1] [40 CFR Part 63, Subpart CC]

(a) Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, which are incorporated by reference as 326 IAC 20-16-1~~, for the tanks as specified in the table above~~. A copy of this rule is included as Attachment D. This source is subject to the following requirements of 40 CFR Part 63, Subpart CC:

(1) 40 CFR 63.640 ~~(a)(1,2), (c)(5,7)~~
(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

**Comment 10:** Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 61, Subpart FF, in Section E.10.

**Response 10:** The following changes will be made to the Facility Description in Section E.10:

**SECTION E.10 FACILITY OPERATION CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

~~(pp) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:~~

~~(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.~~

~~Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.~~

~~(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.~~

~~(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.~~

~~Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.~~

~~Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.~~

~~Under 40 CFR 60, Subpart GGGa, valves are considered affected facilities at a petroleum refinery.~~

~~Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.~~

**Under 40 CFR 61, Subpart FF, this stationary petroleum refinery is considered an affected facility.**

**Comment 11:** Countrymark Cooperative, LLP proposes to change the applicable sections of 40 CFR 61, Subpart FF, in Section E.10.

**Response 11:** The following changes will be made to Condition E.10.2:

E.10.2 Benzene Waste Operations NESHAP [40 CFR Part 61, Subpart FF]

Pursuant to 40 CFR Part 61, Subpart FF, the Permittee shall comply with the National Emission Standards for Benzene Waste Operations which are incorporated as reference as 326 IAC 14-1-1 ~~for new and existing drains~~. A copy of this rule is included as Attachment K. This source is subject to the following requirements of 40 CFR Part 61, Subpart FF:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356(a)(b)(1)**,(b)(5)**
(6) 40 CFR 61.357(a)(c)

**Comment 12:** Countrymark Cooperative, LLP proposes to remove Appendix A to 40 CFR 61 from Attachment K because it adds a great number of pages to the permit and is not referenced in any requirement in 40 CFR 61, Subpart FF.

**Response 12:** Appendices which are not referenced in 40 CFR 61, Subpart FF will be omitted from Attachment K.

**Comment 13:** Countrymark Cooperative, LLP proposes to revise the affected facilities under 40 CFR 60, Subpart GGGa, in Section E.11.

**Response 13:** The following changes will be made to the Facility Description in Section E.11:

~~(pp) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:~~

~~(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.~~

~~Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.~~

~~(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.~~

~~(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.~~

~~Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.~~

~~Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.~~

~~Under 40 CFR 61, Subpart FF new and existing drains are considered affected facilities for benzene waste operations.~~

**Each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service constructed, reconstructed, or modified after November 7, 2006.**

Under 40 CFR 60, Subpart GGGa, ~~valves~~ **these units** are considered affected facilities at a petroleum refinery.

**Comment 14:** Countrymark Cooperative, LLP proposes to add applicable sections of 40 CFR 60, Subpart GGGa, in Section E.11.

**Response 14:** The following changes will be made to Condition E.11.2:

E.11.2 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS [40 CFR Part 60, Subpart GGGa]

Pursuant to 40 CFR Part 60, Subpart GGGa, the Permittee shall comply with the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after November 7, 2006 which are incorporated as 326 IAC 12-1-1, for the ~~valves~~ **components** specified above. A copy of this rule is included as Attachment J. The source is subject to the following requirements of 40 CFR Part 60, Subpart GGGa:

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a
**(4) 40 CFR 60.593a**

**Comment 15:** Countrymark Cooperative, LLP proposes to revise the description of sources that are affected facilities under 40 CFR 60, Subpart Ja, in Section E.12.

**Response 15:** The following changes will be made to the Facility Description in Section E.12:

Facility Description [326 IAC 2-7-5(15)]

(e) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 MMBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 MMBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118;

**(pp) One (1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.**

Under 40 CFR Part 60, Subpart Ja, these units are considered an affected facilities.

**Comment 16:** Countrymark Cooperative, LLP proposes to add applicable sections of 40 CFR 60, Subpart Ja.

**Response 16:** The following changes will be made to Condition E.12.2:

E.12.2 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS [40 CFR Part 60, Subpart Ja (**Certain Sections** Currently Under **Indefinite** Stay)]

Pursuant to 40 CFR Part 60, Subpart Ja, the Permittee comply with the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after May 14, 2007, for the refinery flare **and LSG Reactor Charge Heater** specified above. A copy of this rule is included as Attachment L. The source is subject to the following requirements of 40 CFR Part 60, Subpart Ja:

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(g)**, (h)**
**(4) 40 CFR 60.103a**
**(5) 40 CFR 60.104a**
**(6) 40 CFR 60.107a**
**(7) 40 CFR 60.108a**

**OAQ Changes**

IDEM has modified the language for several standard Title V permitting Conditions under Sections B and C. Necessary administrative changes to the Part 70 Operating Permit Renewal No. T129-25424-00003, will be noted in this addendum only, as no changes will be made to the TSD.

Pursuant to the provisions of 326 IAC 2-7-11, the permit is hereby administratively amended as follows with the deleted language as ~~strikeouts~~ and new language **bolded**.

The Table of Contents has been updated accordingly

**Change No. 1:** For clarity, IDEM has changed references to the general conditions: "in accordance with Section B", "in accordance with Section C", or other similar language, to " Section C ... contains the Permittee's obligations with regard to the records required by this condition."

**Change No. 2:** The phrases "no later than" and "not later than" are clearer than "within" in relation to the end of a timeline. Therefore all timelines have been switched to "no later than" or "not

later than" except for the timelines for Title V Fee, Emergency Provisions, Continuous Compliance Plan, and Revocation of Permits (Conditions newly numbered as B.11, B.15, B.23, and C.10) because the underlying rules state "within."

**Change No. 3:** 326 IAC 2-7 requires that "a responsible official" perform certain actions. 326 IAC 2-7-1(34) allows for multiple people to meet the definition of "responsible official." Therefore, IDEM is revising all instances of "the responsible official" to read "a responsible official."

**Change No. 4:** In order to clarify what rule requirements need to be met through certification, the last sentence dealing with the need for certification has been removed from the form(s) because the Condition(s) requiring the form(s) already address this issue.

**Change No. 5:** To clarify that Section B - Certification only states what a certification must be, IDEM has revised the condition.

**Change No. 6:** IDEM has revised Section B - Preventive Maintenance Plan.

**Change No. 7:** IDEM, OAQ has revised Section B - Emergency Provisions to delete paragraph (h). 326 IAC 2-7-5(3)(C)(ii) allows that deviations reported under an independent requirement do not have to be included in the Quarterly Deviation and Compliance Monitoring Report.

**Change No. 8:** IDEM has added the Southeastern Regional Office to Section B - Emergency Provisions.

**Change No. 9:** Having a separate condition for the reporting of deviations is unnecessary. Therefore, IDEM has removed Section B - Deviation form Permit Requirements and Conditions and added the requirements of that condition to Section C - General Reporting Requirements. Paragraph (d) of Section C - General Reporting Requirements has been removed because IDEM already states the timeline and certification needs of each report in the condition requiring the report. Because this source is Major for PSD, Subparagraph (g)(4) has be revised to match the underlying rule language.

**Change No. 10:** IDEM, OAQ will state which rule establishes the authority to set a deadline for the Permittee to submit additional information. Therefore, Section B - Permit Renewal has been revised.

**Change No. 11:** IDEM, OAQ will state that no notice is required for approved changes in Section B - Permit Revision Under Economic Incentives and Other Programs.

**Change No. 12:** IDEM has added 326 IAC 5-1-1 to the exception clause of Section C - Opacity, since 326 IAC 5-1-1 does list exceptions.

**Change No. 13:** IDEM has revised Section C - Incineration to more closely reflect the two underlying rules.

**Change No. 14:** IDEM has removed the first paragraph of Section C - Performance Testing due to the fact that specific testing conditions elsewhere in the permit will specify the timeline and procedures.

**Change No. 15:** IDEM has revised Section C - Compliance Monitoring. The reference to recordkeeping has been removed due to the fact that other conditions already address recordkeeping. The voice of the condition has been change to clearly indicate that it is the Permittee that must follow the requirements of the condition.

**Change No. 16:** IDEM has removed Section C - Monitoring Methods. The conditions that require the monitoring or testing, if required, state what methods shall be used.

**Change No. 17:** IDEM has revised Section C - Response to Excursions or Exceedances. The

introduction sentence has been added to clarify that it is only when an excursion or exceedance is detected that the requirements of this condition need to be followed. The word "excess" was added to the last sentence of paragraph (a) because the Permittee only has to minimize excess emissions. The middle of paragraph (b) has been deleted as it was duplicative of paragraph (a). The phrase "or are returning" was added to subparagraph (b)(2) as this is an acceptable response assuming the operation or emission unit does return to normal or its usual manner of operation. The phrase "within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable" was replaced with "normal or usual manner of operation" because the first phrase is just a limited list of the second phrase. The recordkeeping required by paragraph (e) was changed to require only records of the response because the previously listed items are required to be recorded elsewhere in the permit.

**Change No. 18:** IDEM has revised Section C - Actions Related to Noncompliance Demonstrated by a Stack Test. The requirements to take response steps and minimize excess emissions have been removed because Section C - Response to Excursions or Exceedances already requires response steps related to exceedances and excess emissions minimization. The start of the timelines was switched from "the receipt of the test results" to "the date of the test." There was confusion if the "receipt" was by IDEM, the Permittee, or someone else. Since the start of the timelines has been moved up, the length of the timelines was increased. The new timelines require action within a comparable timeline; and the new timelines still ensure that the Permittee will return to compliance within a reasonable timeframe.

**Change No. 19:** Paragraph (b) of Section C - Emission Statement has been removed. It was duplicative of the requirement in Section C - General Reporting Requirements.

**Change No. 20:** The voice of paragraph (b) of Section C - General Record Keeping Requirements has been changed to clearly indicate that it is the Permittee that must follow the requirements of the paragraph.

**Change No. 21:** IDEM has simplified the referencing in Section C - Compliance with 40 CFR 82 and 326 IAC 22-1.

The changes No.1 through No. 21 have been made to the B and C Sections of the permit. Below is the previous version of the B and C Sections in strike-through, and the updated version of the B and C Sections in bold type:

***Previous B and C Sections***

~~**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(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]~~

~~(a) This permit, T117-23297-00014, 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 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.~~

~~(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]~~

~~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. The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34). 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 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]~~

~~(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by the "responsible official" of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.~~

~~(b) One (1) certification shall be included, using the attached Certification Form, 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(34).~~

~~B.9 Annual Compliance Certification [326 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 V~~
~~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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)][326 IAC 2-7-6(1) and (6)][326 IAC 1-6-3]~~

~~(a) If required by specific condition(s) in Section D of this permit, the Permittee shall maintain and implement Preventive Maintenance Plans (PMPs) 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.~~

~~(b) 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 or potential to emit. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(c) 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, and 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 Section), or~~
~~Telephone Number: 317-233-0178 (ask for Compliance Section)~~
~~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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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)(9) 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.~~

~~(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report. Any emergencies that have been previously reported pursuant to paragraph (b)(5) of this condition and certified by the "responsible official" need only referenced by the date of the original report.~~

~~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 T117-23297-00014 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.~~

~~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 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]~~

~~(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported 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~~

~~using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. 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.~~

~~The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.~~

~~B.16 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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.17 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(40). The renewal application does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~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 in writing by IDEM, OAQ any additional information identified as being needed to process the application.~~

~~B.18 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) 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 shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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.19 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 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.20 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),(c), or (e) 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 V
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),(c), or (e). 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), (c)(1), and (e)(2).~~

~~(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(36)) 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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(9). 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.~~

~~B.21 Source Modification Requirement [326 IAC 2-7-10.5]~~

~~(a) A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-7-10.5.~~

~~(b) Any modification at an existing major source is governed by the requirements of 326 IAC 2-2 (for sources located in NA areas).~~

~~B.22 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.23 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~~

~~The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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.24 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.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 5-1-3 (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 or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2.~~

~~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).~~

~~C.6 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(2).~~

~~(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(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 61-52 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 by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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 Accredited 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 Accredited Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Accredited Asbestos inspector is not federally enforceable.~~

**~~Testing Requirements [326 IAC 2-7-6(1)]~~**

~~C.7 Performance Testing [326 IAC 3-6]~~

~~(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.~~

~~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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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 certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(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.8 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.9 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]~~

~~Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, 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~~
~~Indianapolis, Indiana 46204-2251~~

~~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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.~~

~~C.10 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]~~

~~(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment.~~

~~(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.~~

~~(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.~~

~~(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.~~

~~(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.~~

~~(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.~~

~~(3) Method 9 readings may be discontinued once a COMS is online.~~

~~(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.~~

~~(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).~~

~~C.11 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]~~

~~(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment.~~

~~(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.~~

~~(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup CEMS shall be brought online within four (4) hours of shutdown of the primary CEMS, and shall be operated until such time as the primary CEMS is back in operation.~~

~~(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 63.1572 (b).~~

~~C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]~~

~~Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60, Appendix B, 40 CFR 63, or other~~

~~approved methods as specified in this permit.~~

~~C.13 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.~~

~~(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.14 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 prepared and submitted written emergency reduction plans (ERPs) consistent with safe operating procedures in March 2002.~~

~~(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.15 Risk Management Plan [326 IAC 2-7-5(12)] [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.16 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]~~

~~(a) Upon detecting an excursion or exceedance, the Permittee shall 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 emissions.~~

~~(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:~~

~~(1) initial inspection and evaluation;~~

~~(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or~~

~~(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.~~

~~(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 maintain the following records:~~

~~(1) monitoring data;~~

~~(2) monitor performance data, if applicable; and~~

~~(3) corrective actions taken.~~

~~C.17 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 take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.~~

~~(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred twenty (120) 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 the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

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

~~C.18 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]~~

~~(a) 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 (32) ("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~~
~~MC 61-50 IGCN 1003~~
~~Indianapolis, Indiana 46204-2251~~

~~The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(b) The emission statement 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.19 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. 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, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.~~

~~(c) If there is a "project" (as defined in 326 IAC 2-2-1 (qq)) and/or 326 IAC 2-3-1(ll)) 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(cc) and/or 326 IAC 2-3-1(z)) and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:~~

~~(1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) 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(rr)(2)(A)(iii) and/or 326 IAC 2-3-1 (mm)(2)(A)(iii); and~~

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

~~(2) 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~~

~~(3) 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.20 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2]~~

~~(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(b) The report required in (a) of this condition and reports required by conditions in Section D of 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~~

~~(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) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(e) 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.~~

~~(f) If the Permittee is required to comply with the recordkeeping provisions of (c) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll) 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 (xx) and/or 326 IAC 2-3-1 (qq), 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).~~

~~(g) The report for project at an existing emissions unit shall be submitted within 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 (c)(2) and (3) 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 deems fit to include in this report.~~

~~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~~

~~(h) 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.21 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 the standards for recycling and emissions reduction:~~

~~(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.~~

~~(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.~~

~~(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.~~

***Updated B and C Sections***

**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(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]**

**(a) This permit, T117-23297-00014, 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 13-15-5-3. 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 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]**

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

**(i) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(34), and**

**(ii) the certification is 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(34).**

**B.9 Annual Compliance Certification [326 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 V**
**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.**

**(d) 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(34).**

**B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)][326 IAC 2-7-6(1) and (6)][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(34).**

**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(34).**

**(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 and Southeast 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.**
**Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058.**

**(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(34).**

**(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)(9) 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 T117-23297-00014 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**

**(4) 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(34).**

**(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(40). 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(34).**

**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] [40 CFR 72]**

**(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(34).**

**(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),(c), or (e) 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 V**
**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),(c), or (e). 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), (c)(1), and (e)(2).**

**(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(36)) 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(34).**

**(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(9). 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 $SO_2$ or $NO_X$ under 326 IAC 21 or 326 IAC 10-4.**

**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(34).**

**(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(16)] [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 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(2).**

**(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(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(34).**

**(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.7 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(34).**

**(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(34).**

**(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.8 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.9 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]**

**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 or of initial start-up, whichever is later, 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 or the date of initial startup, whichever is later, 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**
**Indianapolis, Indiana 46204-2251**

**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(34).**

**Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.**

**C.10 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]**

**(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment.**

**(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.**

**(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.**

**(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.**

**(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.**

**(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.**

**(3) Method 9 readings may be discontinued once a COMS is online.**

**(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.**

**(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).**

**C.11 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]**

**(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment.**

**(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.**

**(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, a calibrated backup CEMS shall be brought online within four (4) hours of shutdown of the primary CEMS, and shall be operated until such time as the primary CEMS is back in operation.**

**(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 63.1572 (b).**

**C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]**

**Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60, Appendix B, 40 CFR 63, or other approved methods as specified in this permit.**

**C.13 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.**

**(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.14 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.15 Risk Management Plan [326 IAC 2-7-5(12)] [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.16 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); or**

**(3) 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.17 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(34).**

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

**C.18 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);**

**(3) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("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**
**MC 61-50 IGCN 1003**
**Indianapolis, Indiana 46204-2251**

**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(34).**

**C.19 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]**

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

**(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. 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(34). 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.**

**Stratospheric Ozone Protection**

**C.21 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.**

**Change No. 22:** In accordance with Change No. 6, the following changes have been made to the D Sections of the Permit:

D.1.1 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan~~, in accordance with Section B - Preventive Maintenance Plan, of this permit,~~ is required for **the Truck loading rack, identified as Loading Rack** 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.**

*******

D.2.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

~~A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the CCR platformer heater, identified as 300 - H1, H2, H3, FCCU regenerator, identified as 500V-5, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), Low Sulfur Gasoline Unit (LSG), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) and any control devices.~~

**A Preventive Maintenance Plan is required for the CCR platformer heater, identified as 300 - H1, H2, H3, FCCU regenerator, identified as 500V-5, Hydrotreater Unit Reactor Charge heater (122), Hydrotreater Unit Stabilizer Reboiler Heater (123), Low Sulfur Gasoline Unit (LSG), and Gas Treatment System & Sulfur Recovery System consisting of TGTU Incinerator Burner (124-2) and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.**

D.3.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

~~A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for all of the storage tanks listed above and any control devices.~~

**A Preventive Maintenance Plan is required for these facilities and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.**

D.4.1 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

~~A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the two (2) sets of oil/water separators, all pipeline valves, open ended valves, flanges, pump seals, compressor seals, vessel relief valves, the Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit, and Tail Gas Treatment Unit and any control devices.~~

**A Preventive Maintenance Plan is required for the two (2) sets of oil/water separators, all pipeline valves, open ended valves, flanges, pump seals, compressor seals, vessel relief valves, the Hydrotreater Unit, Amine Unit, Sulfur Recovery Unit, and Tail Gas Treatment Unit and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.**

D.5.5 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

~~A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for the one (1) Main Refinery Flare, identified as 700-V101, one (1) Crude heater equipped with a Low-NOx burner, identified as C-II, one (1) Unifiner heater, identified as 400-H5, one (1) Cycle oil heater, identified as H-H2, one (1) Naphtha splitter heater, identified as 900-H1, one (1) Vacuum heater, identified as 200-H4, one (1) Old Platformer heater, identified as Naptha S;litter Reboiler 900-H2, one (1) Alkylation unit heater, identified as 100-H1, one (1) Auxiliary crude heater, identified as 200-H1, one (1) Platformer stabilizer , identified as 300-H4, four (4) boilers, identified as B1, B2, B3, B4, one (1) Vacuum heater husky, identified as 200-H3, One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101, and any control devices.~~

**A Preventive Maintenance Plan is required for the one (1) Main Refinery Flare, identified as 700-V101, one (1) Crude heater equipped with a Low-NOx burner, identified as C-II, one (1) Unifiner heater, identified as 400-H5, one (1) Cycle oil heater, identified as H-H2, one (1) Naphtha splitter heater, identified as 900-H1, one (1) Vacuum heater, identified as 200-H4, one (1) Old Platformer heater, identified as Naptha S;litter Reboiler 900-H2, one (1) Alkylation unit heater, identified as 100-H1, one (1) Auxiliary crude heater, identified as 200-H1, one (1) Platformer stabilizer , identified as 300-H4, four (4) boilers, identified as B1, B2, B3, B4, one (1) Vacuum heater husky, identified as 200-H3, One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as 500-H101, and their control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.**

**Change No. 23:** In accordance with Change No. 1, the following changes have been made to the D Sections of the Permit:

D.3.3 Record Keeping Requirements [326 IAC 8-4-3]

***

(b) ~~All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.~~ **Section C - General Record Keeping Requirements, of this permit contains the Permittee's obligations with regard to the records required by this condition.**

D.5.8 Record Keeping Requirements

(a) To document **the** compliance **status** with Conditions D.5.3 and D.5.4, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;
(2) Actual No. 6 residual fuel oil usage per month since last compliance determination period and equivalent $SO_2$ emissions;
(3) A certification, signed by the Permittee, that the records of the fuel supplier certifications represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications.
(5) The name of the fuel supplier; and
(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document **the** compliance **status** with Condition D.5.5, the Permittee shall maintain daily records of visible emission notations of the four boiler stacks (B1, B2, B3, and B4) once per day or maintain a record of the reason why the visible emission notations were not taken.

(c) ~~All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.~~ **Section C - General Record Keeping Requirements, of this permit contains the Permittee's obligations with regard to the records required by this condition.**

# Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a
Part 70 Operating Permit Renewal

## Source Background and Description

| | |
|---|---|
| **Source Name:** | **Countrymark Cooperative, LLP** |
| **Source Location:** | **1200 Refinery Road, Mount Vernon, Indiana** |
| **County:** | **Posey** |
| **SIC Code:** | **2911** |
| **Permit Renewal No.:** | **T129-25424-00003** |
| **Permit Reviewer:** | **Roger Osburn** |

The Office of Air Quality (OAQ) has reviewed the operating permit renewal application from Countrymark Cooperative, LLP relating to the operation of a petroleum refinery.

## History

On July 21, 2003, Countrymark Cooperative, LLP was issued a Part 70 Operating Permit. On October 18, 2007, Countrymark Cooperative, LLP submitted an application to the OAQ requesting to renew its operating permit.

## Source Definition

This company consists of two (2) plants:

(a) Plant 1, the refinery, is located at 1200 Refinery Road, Mount Vernon, Indiana 47620; and,

(b) Plant 2, the river dock terminal, is located at South Mann Street and Ohio Street, Mount Vernon, Indiana 47620.

On November 24, 2003, in Significant Permit Modification (129-17940-00003), a source determination concluded that Plant 1 (the refinery) and Plant 2 (the river dock terminal) are under the common control of Countrymark Cooperative, LLP and will be considered one source. These two plants are considered one source because they are located on adjacent properties, are under common ownership, and belong to the same industrial grouping. Therefore, the term “source” in the Part 70 documents refers to both Plant 1 and Plant 2 as one source.

Separate Part 70 renewal permits are being issued to Countrymark Cooperative, LLP, solely for administrative purposes:

(a) Plant 1, 129-00003: T129-25424-00003

(b) Plant 2, 129-00037: T129-25574-00037

## Permitted Emission Units and Pollution Control Equipment

(a) One (1) Truck loading rack, with a maximum capacity of 60,000 gallons of submerged loading of gasoline, kerosene or distillate oil per hour, installed in 1958, identified as Loading Rack, and exhausting to stack 65; controlled by the Loading Rack Flare, equipped with a 0.09 million British Thermal Units per hour (mmBtu/hr) natural gas fired pilot and designed to handle 160 actual cubic feet per minute (acfm) of hydrocarbon vapors, installed in 1998, and exhausting to stack 1D. Under 40 CFR 63, Subpart R, this facility is considered an existing bulk gasoline terminal.

(b) One (1) Fluid Catalytic Cracking Unit (FCCU) Raw Oil Pre-heater, identified as H-101 with a maximum heat input rate of 18.1 million British Thermal Units per hour (mmBtu/hr), combusting refinery fuel gas only (no sour water stripper overhead off-gas combustion), installed in 1945 and exhausting to stack 9;

(c) One (1) FCCU regenerator, identified as V-5 with an average throughput rate of 380 barrels fresh feed per hour, installed in 1950, controlled by a cyclone and exhausting to stack 10. Under 40 CFR 63, Subpart UUU, process vents on the FCCU are considered affected sources at a petroleum refinery.

(d) The following storage vessels:

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 1 | fixed roof cone tank | 404,418 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 075; |
| 2 | fixed roof cone tank | 404,502 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 076; |
| 3 | fixed roof cone tank | 404,334 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 077; |
| 4 | fixed roof cone tank | 118,272 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 018; |
| 5 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 019; |
| 6 | fixed roof cone tank | 120,456 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 020; |
| 7 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 078; |
| 8 | fixed roof cone tank | 126,000 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 079; |
| 9 | fixed roof cone tank | 204,204 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 023; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 10 | fixed roof cone tank | 121,590 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1940 | - | 024; |
| 11A | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 080; |
| 11B | fixed roof cone tank | 8,820 | 168,000 | oil water / mixture | 1972 | - | 081; |
| 12 | fixed roof cone tank | 6,090 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 082; |
| 15 | fixed roof cone tank | 24,654 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 083; |
| 17 | fixed roof cone tank | 997,584 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1941 | - | 030; |
| 18 | internal floating roof tank/ mechanical primary seal | 1,052,013 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2003 | 40 CFR Part 60, Subpart Kb | 037; |
| 19 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 616,938 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 032; |
| 21 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,002,750 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 034; |
| 22A | fixed roof cone tank | 1,050,000 | 84,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure No. 2 fuel oil | 2003 | 40 CFR 63, Subpart CC | 120; |
| 22B | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 127; |
| 24 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 588,714 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1985 | 40 CFR Part 60, Subpart Kb | 037; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 25 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 656,614 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 038; |
| 26 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 1,006,068 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1941 | - | 039; |
| 33 | fixed roof cone tank | 2,262,960 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 085; |
| 34 | fixed roof cone tank | 984,480 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 045; |
| 35 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 997,962 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate, | 1946 | - | 046; |
| 36 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,261,954 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of jet kerosene, | 1946 | - | 047; |
| 37 | fixed roof cone tank | 2,247,126 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1946 | - | 048; |
| 38 | fixed roof cone tank | 2,248,386 | 210,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 049;; |
| 39 | fixed roof cone tank | 2,250,234 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1948 | - | 050; |
| 40 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,222,388 | 336,000 | RVP 15 Gasoline, | 1949 | - | 051; |
| 41 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,204,244 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1949 | - | 052; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 42 | fixed roof cone tank | 2,261,574 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1950 | - | 053; |
| 43 | fixed roof cone tank | 2,254,098 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1951 | - | 054; |
| 44 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 055; |
| 45 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 2,310,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1951 | - | 056; |
| 46 | fixed roof cone tank/mechanical primary seal | 3,402,000 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of Distillate, | 1955 | - | 057; |
| 47 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 5,040,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1976 | 40 CFR Part 60, Subpart K | 058; |
| 48 | fixed roof cone tank/external floating roof tank /mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 059; |
| 49 | fixed roof cone tank/ external floating roof tank /mechanical primary seal | 4,032,000 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1958 | - | 060; |
| 50 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,934,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1965 | - | 061; |
| 51 | fixed roof cone tank/internal floating roof tank/mechanical primary seal | 3,937,266 | 336,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1973 | - | 062; |
| 52 | fixed roof cone tank | 3,935,148 | 336,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1976 | 40 CFR Part 60, Subpart K | 063; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 53 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 086; |
| 54 | fixed roof cone tank | 16,926 | 168,000 | Ethanol, | 1985 | - | 087; |
| 55 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 088; |
| 56 | fixed roof cone tank | 11,634 | 168,000 | Ethanol, | 1980 | - | 089; |
| 58 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1980 | - | 102; |
| 159 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 103; |
| 160 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 104; |
| 161 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 105; |
| 162 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1994 | - | 106; |
| 163 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 107; |
| 164 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1983 | - | 108; |
| 165 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 109; |
| 166 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 110; |
| 167 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1985 | - | 111; |

| Tank ID | Tank Description | Max. Capacity (gallons) | Max. Withdrawal Rate (gal/hr) | Material Stored | Construction Date | NSPS and NESHAP applicability | Stack ID |
|---|---|---|---|---|---|---|---|
| 168 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure no higher than the vapor pressure of jet naptha, | 1988 | - | 112; |
| 169 | fixed roof cone tank | 16,800 | 168,000 | hydrocarbon with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 1989 | - | 113; |
| 125 | fixed roof cone tank | 157,000 | 6,000 | hydrocarbon with vapor pressure of No.2 fuel oil or less | 2005 | - | 015; |
| 173 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2006 | - | 128; |
| 174 | fixed roof cone tank/insulated/ heated cone tank | 1,050,000 | 16,800 | Residual Fuel Oil (No.6) or Petroleum Material with a vapor pressure equivalent to or less than No.2 distillate, | 2007 | - | 129 |
| 175 | fixed roof cone tank/internal floating roof tank/liquid mounted primary seal | 2,310,000 | 210,000 | Petroleum with vapor pressure equal to or less than the vapor pressure of 13 RVP gasoline, | 2008 | 40 CFR Part 60, Subpart Kb | 130 |

(e) One (1) Main Refinery Flare, identified as RCD-1 with a maximum heat input rate of 371 mmBtu/hr of refinery fuel gas/process gas (with capacity for a supplementary pilot fuel heat input rate of 3.0 mmBtu/hr), installed in 1945 and replaced in 2006 and exhausting to stack 118;

Under 40 CFR Part 60, Subpart Ja, the Main Refinery Flare is considered an affected facility.

(f) One (1) Crude heater equipped with a Low-NOx burner, identified as C-II with a maximum heat input rate of 131 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1955 and exhausting to stack 1;

(g) One (1) Unifiner heater, identified as H-H5 with a maximum heat input rate of 20 mmBtu/hr, combusting refinery fuel gas, installed in 1959 and exhausting to stack 2;

(h) One (1) Cycle oil heater, identified as H-H2 with a maximum heat input rate of 10 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 3;

(i) One (1) Naphtha splitter heater, identified as H-H3 with a maximum heat input rate of 12.2 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 4;

(j) One (1) Vacuum heater, identified as V-IV with a maximum heat input rate of 14.1 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1950, modified in 2007, and exhausting to stack 5;

(k) One (1) Old Platformer heater, identified as P-H1 with a maximum heat input rate of 29 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 6;

(l) One (1) Alkylation unit heater, identified as A-H1 with a maximum heat input rate of 13.2 mmBtu/hr, combusting refinery fuel gas and No. 6 residual fuel oil, installed in 1966 and exhausting to stack 7;

(m) One (1) Auxiliary crude heater, identified as C-I with a maximum heat input rate of 10.1 mmBtu/hr, combusting refinery fuel gas, installed in 1966 and exhausting to stack 11;

(n) One (1) Platformer stabilizer reb, identified as P-H2 with a maximum heat input rate of 5.92 mmBtu/hr, combusting refinery fuel gas, installed in 1956 and exhausting to stack 12;

(o) One (1) no. 1 boiler, with a maximum heat input rate of 52 mmBtu/hr of process gas and/or No. 6 residual oil, identified as B1 and exhausting to stack 8;

(p) One (1) no. 2 boiler, with a maximum heat input rate of 65 mmBtu/hr of residual oil and/or process gas, identified as B2 and exhausting to stack 13;

(q) One (1) no. 3 boiler, with a maximum heat input rate of 52 mmBtu/hr of residual oil and/or process gas, identified as B3 and exhausting to stack 14;

(r) One (1) Vacuum heater husky, identified as VIII with a maximum heat input rate of 6.27 mmBtu/hr, combusting refinery fuel gas No. 6 residual fuel oil, installed in 1963 and exhausting to stack 64;

(s) One (1) CCR Platformer Unit which includes one (1) CCR Platformer Heater, identified as 300 - H1, H2, H3 with a maximum heat input rate of 70.3 mmBtu/hr, combusting refinery fuel gas, installed in 1992 and exhausting to stack 74. Under 40 CFR 63, Subpart UUU, process vents on the CCR are considered affected sources at a petroleum refinery.

(t) Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071. Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected sources at a petroleum refinery.

(u) one (1) Miscellaneous operation (Sampling, Blowing, Purging, etc.), identified as 073;

(v) Pipeline Valves - Gas, identified as 090. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(w) Pipeline Valves - Light Liquid, identified as 091. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(x) Pipeline Valves - Heavy Liquid, identified as 092. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(y) Pipeline Valves - Hydrogen, identified as 093. Under 40 CFR 60, Subpart GGG, valves are considered affected sources at a petroleum refinery.

(z) Open Ended Valves, identified as 094. Under 40 CFR 60, Subpart GGG, open-ended valves are considered affected sources at a petroleum refinery.

(aa) Flanges, identified as 095. Under 40 CFR 60, Subpart GGG, the flanges are affected considered sources at a petroleum refinery.

(bb) Pump Seals Light Liquid, identified as 096. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(cc) Pump Seals Heavy Liquid, identified as 097. Under 40 CFR 60, Subpart GGG, equipment associated with the pump is considered an affected source at a petroleum refinery.

(dd) Compressor Seals - Gas, identified as 098. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ee) Compressor Seals - Heavy Liquid, identified as 099. Under 40 CFR 60, Subpart GGG, equipment associated with compressor is considered an affected source at a petroleum refinery.

(ff) Drains, identified as 100.

(gg) Vessel Relief Valves, identified as 101. Under 40 CFR 60, Subpart GGG, pressure relief devices are considered affected sources at a petroleum refinery.

(hh) Cooling Towers, identified as 119; and

(ii) Process units made up of vessels, piping, exchangers, identified as PENEX. Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery.

(jj) One (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, with a maximum heat input rating of 19.25 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 122, constructed in 2005.

(kk) One (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, with a maximum heat input rating of 19.94 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural gas as a back up fuel, and exhausting through one (1) stack identified as 123, constructed in 2005.

(ll) One (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124 and consisting of the following: Under 40 CFR 63, Subpart UUU, these facilities and the associated process vents and bypass lines are considered affected sources at a petroleum refinery.

(1) One (1) Claus Unit Startup burner (520-H-101), identified as 124-1, with a maximum heat input rating of 1.54 MMBtu per hour, combusting natural gas, and exhausting through one (1) stack identified as 124-1, constructed in 2005.

(2) One (1) Tail Gas Treating Unit (TGTU) Incinerator burner (520-H-101), identified as 124-2, with a maximum heat input rating of 1.29 MMBtu per hour, combusting refinery fuel gas as a primary fuel and natural as a back fuel, and exhausting through one (1) stack identified as 124-2, constructed in 2005. In the event of unscheduled shutdown of the CCR unit, the Sulfur Recovery Unit effluent will be routed directly to the TGTU incinerator.

(3) One (1) Tail Gas Treating Unit (TGTU) Incinerator (520-H-162), identified as 124-3, with a maximum process flow rate of 48,000 dry standard cubic feet per day, and exhausting through one (1) stack identified as 124-3, constructed in 2005.

(4) One (1) Sour Flare (520-H-163), identified as 124-4, with a maximum burner capacity of 0.92 MMBtu per hour, and a maximum process flow rate of 200 standard cubic feet per hour, and exhausting through one (1) stack identified as 124-4, constructed in 2005.

(mm) Fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit consisting of: Under 40 CFR 60, Subpart GGG, equipment associated with the sampling connection system is considered an affected source at a petroleum refinery. Under 40 CFR 63, Subpart CC, equipment leaks from storage vessels and equipment leaks associated with a bulk gasoline terminal are considered affected sources.

(1) pipeline Valves - Gas, identified as 090;
(2) pipeline Valves - Light Liquid, identified as 091;
(3) pipeline Valves - Heavy Liquid, identified as 092;
(4) pipeline Valves - Hydrogen, identified as 093;
(5) open Ended Valves, identified as 094;
(6) Miscellaneous (Sampling, Blowing, Purging, etc.), identified as 073;
(7) flanges, identified as 095;
(8) pump Seals Light Liquid, identified as 096;
(9) pump Seals Heavy Liquid, identified as 097;
(10) compressor Seals - Gas, identified as 098;
(11) compressor Seals - Heavy Liquid, identified as 099;
(12) drains, identified as 100;
(13) vessel Relief Valves, identified as 101; and
(14) cooling Towers, identified as 119.

(nn) One (1) Vacuum heater, identified as 200-H6, with a maximum heat input rate of 5.49 mmBtu/hr, combusting refinery fuel gas and natural gas as a backup, installed in 2005 and exhausting to stack 126.

(oo) One (1) boiler, identified as No. 4 boiler constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, and exhausting to stack 131.

Under the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS (40 CFR 60, Subpart Dc), the boiler identified as B4 above, is considered an affected facility new source.

Under the Standards of Performance for Petroleum Refineries (40 CFR Part 60, Subpart J), the boiler identified as B4 above, is considered an affected facility.

(pp) One (1) Low Sulfur Gasoline (LSG) Unit consisting of the following equipment:

(1) LSG Reactor Charge Heater (810-H101) approved for construction in 2008, with a maximum capacity of 5.985 MMBtu, combusting refinery fuel gas only, and venting to stack 128.

Under 40 CFR Part 60, Subpart Ja, the LSG Reactor Charge Heater is considered an affected facility.

(2) #5 Cooling Tower with a maximum capacity of 3,600 gpm approved for construction in 2008.

(3) LSG Unit components and drains (800 valves, 16 drains, and 5 pumps) approved for construction in 2008.

Under 40 CFR 63, Subpart CC, equipment leaks associated with a petroleum refinery are considered as an affected facility.

Under 40 CFR 60, Subpart QQQ, new and existing drains are considered affected facilities at a petroleum refinery.

Under 40 CFR 60, Subpart GGG, valves are considered affected facilities at a petroleum refinery.

Under 40 CFR 61 Subpart FF new and existing drains are considered affected facilities for benzene waste operations.

**Insignificant Activities**

The source also consists of the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Equipment powered by internal combustion engines such as stationary fire pumps, vehicles, and similar equipment;
(b) construction activities for which a construction permit or other permits are not required.
(c) laboratory testing activities;
(d) RCRA regulated units including land farm maintenance, waste generation units and other related hazardous waste activities;
(e) the following volatile organic compound (VOC) and hazardous air pollutant (HAP) storage containers:
  (1) storage tanks with capacity less than or equal to 1,000 gallons and annual throughput less than 12,000 gallons,
  (2) Vessels storing lubricating oils, hydraulic oils, machining oils, and machining fluids;
(f) space or area heating sources;
(g) tank cleaning;
(h) product transfer, loading and unloading operations not otherwise listed;
(i) crude oil tank truck unloading- two stations;
(j) butane truck unloading -three stations;
(k) propane truck unloading;
(l) butane railroad car unloading;
(m) no. 6 oil loading;
(n) asphalt railroad car loading;
(o) butane pipeline tenders;
(p) natural gas pipeline tenders;
(q) barge loading/unloading;
(r) crude oil pipeline tenders;
(s) product loading/unloading not otherwise listed: Private fuel pump dispensing;
(t) equipment and processes used to collect any material that might be released during a malfunction, process upset, or spill clean-up, including catch tanks/ basins, temporary liquid separators, tanks, and fluid handling equipment;
(u) plant traffic through No. 6 oil loading rack areas;
(v) process unit TURNAROUND maintenance and cleaning activities;
(w) degassing, purging and the otherwise necessary venting of tanks, vessels and piping for inspection, maintenance or repair;
(x) initial charging or firing of process units, flares or other regulated equipment for which reporting is not required ro made;
(y) parts and equipment cleaning using cleaners and solvents characterized as follows:
  (1) having a vapor pressure equal to or less than 2 kPa, measured at 38ºC, or
  (2) having a vapor pressure equal to or less than 0.7 kPa, measured at 20ºC;

(z) metal and related material cutting, fabricating and preparation; [326 IAC 6-3]
(aa) sand blasting or mechanical stripping on tanks and other equipment; [326 IAC 6-3]
(bb) painting on tanks and other equipment; [326 IAC 6-3]
(cc) bulk dry storage and handling of limestone, sand, river silt, and similar materials;
(dd) repair, maintenance and incidental removal of asbestos insulation per Refinery Asbestos Maintenance Plan for which notification under NESHAPS is not required;
(ee) on-site fire and emergency response training exercises;
(ff) tank water draining;
(gg) chemical addition for corrosion protection, defoaming, finished products, flow enhancement, fouling, pH control, and other purposes in boilers, process equipment, waste water operations, cooling towers and other refinery equipment;
(hh) catalyst handling;
(ii) repairs and maintenance on pumps, compressors, pressure vessels, valves, piping and other refinery equipment;
(jj) mechanical Equipment (Cranes, forklifts, etc.);
(kk) plant Traffic (Pumpers, Gaugers and etc.);
(ll) grass cutting operations -weed control;
(mm) operation of the Lime Scrubber;
(nn) welding/Cutting of metal for vessel, pipeline and equipment maintenance. [326 IAC 6-3]
(oo) neutralization pit operations;
(pp) operation of the Waste Water DAF Unit;
(qq) one (1) Vehicle Traffic Paved; and
(rr) one (1) Vehicle Traffic Unpaved.
(ss) one (1) Riverview Crude Oil Storage Tank, used as a backup, constructed in 1973, located at 500 Old Highway 69, Mt. Vernon IN 47620 with a maximum capacity of 80,000 bbl/year and a maximum throughput of 400,000 bbl/year, storing crude oil.

**Existing Approvals**

Since the issuance of the original Part 70 permit 129-7882-00003 on July 21, 2003, the source has constructed or has been operating under the following approvals as well:

Significant Permit Modification No. 129-17940-00003, issued on November 24, 2003
Minor Source Modification No. 129-18135-00003, issued on November 17, 2003
Significant Source Modification No. 129-18672-00003, issued on February 1, 2005
Significant Permit Modification No. 129-20112-00003, issued on March 21, 2005
Administrative Amendment No. 129-20343-00003, issued on March 30, 2005
Minor Source Modification No. 129-21168-00003, issued on June 1, 2005
Significant Permit Modification No. 129-21251-00003, issued on August 15, 2005
Significant Source Modification No. 129-22917-00003, issued on December 8, 2006
Significant Permit Modification No. 129-23090-00003, issued January 30, 2007
Significant Permit Modification No. 129-24761-00003, issued December 17, 2007
Minor Source Modification No. 129-26889-00003, issued on October 10, 2008
Significant Permit Modification No. 129-26980-00003, issued January 27, 2009

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.

The following terms and conditions from previous approvals have been removed in this Part 70 Renewal:

(a) On June 8, 2007, the United States Court of appeals for the District of Columbia Circuit (in NRDC v. EPA, no. 04-1386) vacated in its entirety the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD. Additionally, since the state rule at 326 IAC 20-95 incorporated the requirements of the NESHAP 40 CFR 63, Subpart DDDDD by reference, the requirements of 326 IAC 20-95 are no longer effective.

**Enforcement Issue**

There are no enforcement actions pending.

**Emission Calculations**

See Appendix A of this document for detailed emission calculations.

**County Attainment Status**

The source is located in Posey County.

| Pollutant | Designation |
|---|---|
| $SO_2$ | Better than national standards. |
| CO | Unclassifiable or attainment effective November 15, 1990. |
| $O_3$ | Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1] |
| $PM_{10}$ | Unclassifiable effective November 15, 1990. |
| $NO_2$ | Cannot be classified or better than national standards. |
| Pb | Not designated. |
| [1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.<br>Unclassifiable or attainment effective April 5, 2005, for $PM_{2.5}$. | |

(a) 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 the ozone standards. 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. See the State Rule Applicability for the source section.

(b) Posey County has been classified as attainment for $PM_{2.5}$. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions, and the effective date of these rules is July 15, 2008. Indiana has three years from the publication of these rules to revise its PSD rules, 326 IAC 2-2, to include those requirements. The May 8, 2008 rule revisions require IDEM to regulate PM10 emissions as a surrogate for $PM_{2.5}$ emissions until 326 IAC 2-2 is revised.

(c) Posey County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability for the source section.

(d) On October 25, 2006, the Indiana Air Pollution Control Board finalized a rule revision to 326 IAC 1-4-1 revoking the one-hour ozone standard in Indiana.

**Unrestricted Potential Emissions**

This table reflects the unrestricted potential emissions of Plant 1.

| Pollutant | tons/year |
|---|---|
| PM | 303 |
| $PM_{10}$ | 138 |
| $SO_2$ | 8711 |
| VOC | 5462 |
| CO | 10,360 |
| $NO_X$ | 852 |

| **HAPs*** | **tons/year** |
|---|---|
| Single HAP | 762 |
| Total HAPs | 1733 |

* HAPs are worst-case; total HAPs include all HAP. See Appendix A for details.

This table reflects the unrestricted potential emissions of Plant 2.

| Pollutant | tons/year |
|---|---|
| PM | - |
| $PM_{10}$ | - |
| $SO_2$ | - |
| VOC | 330.58 |
| CO | - |
| $NO_X$ | - |

| **HAPs*** | **tons/year** |
|---|---|
| Single HAP | 5.29 |
| Total HAPs | 17.33 |

This table reflects the unrestricted potential emissions of the source (Plant #1 and Plant #2).

| Pollutant | tons/year |
|---|---|
| PM | greater than 100 |
| $PM_{10}$ | greater than 100 |
| $SO_2$ | greater than 100 |
| VOC | greater than 100 |
| CO | greater than 100 |
| $NO_X$ | greater than 100 |

| **HAPs*** | **tons/year** |
|---|---|
| Single HAP | Greater than 10 |
| Total HAPs | Greater than 25 |

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of $PM_{10}$, $SO_2$, VOC, $NO_x$, and CO are each greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of all other criteria pollutants are less than one hundred (<100) tons per year.

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is greater than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is greater than twenty-five (25) tons per year.

Fugitive Emissions

This type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-2 or 326 IAC 2-3; therefore, fugitive emissions are counted toward the determination of Part 70 applicability.

**Actual Emissions**

The following table shows the actual emissions from the Plant 1. This information reflects the 2006 OAQ emission data.

| Pollutant | Actual Emissions (tons/year) |
|---|---|
| PM | Not Reported |
| $PM_{10}$ | 55 |
| $SO_2$ | 906 |
| VOC | 171 |
| CO | 172 |
| $NO_x$ | 365 |
| HAP | Not Reported |

The following table shows the actual emissions from the Plant 2. This information reflects the 2006 OAQ emission data.

| Pollutant | Actual Emissions (tons/year) |
|---|---|
| PM | Not Reported |
| $PM_{10}$ | Not Reported |
| $SO_2$ | Not Reported |
| VOC | 3.0 |
| CO | Not Reported |
| $NO_x$ | Not Reported |
| HAP | Not Reported |

**Part 70 Permit Conditions**

This source is subject to the requirements of 326 IAC 2-7, pursuant to which the source has to meet 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 significant emission units after controls. The control equipment is considered federally enforceable only after issuance of this Part 70 operating permit.

| Potential to Emit (tons/year) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Process/facility | PM | PM-10 | $SO_2$ | VOC | CO | $NO_X$ | HAPs |
| Storage Tanks | 0.00 | 0.00 | 0.00 | 4,630.08 | 0.00 | 0.00 | 1,699.7 (total)<br>742.7 (single) |
| Loading Rack / Flare | 0.00 | 0.00 | 0.00 | 26.43 | 0.00 | 0.00 | 1.24 (total)<br>0.42 (single) |
| Process Fugitive Emissions | 0.00 | 0.00 | 0.00 | 132.96 | 0.00 | 0.00 | 6.40 (total)<br>2.22 (single) |
| Combustion Units | 227.87 | 118.69 | 8,710.57 | 366.47 | 10,359.57 | 851.53 | 11.92 (total)<br>11.37 (single) |
| FCCU Regenerator (Catalyst PM emissions) | 0.17 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Oil vaporization from oil/water separator basins and pits | 0.00 | 0.00 | 0.00 | 306.53 | 0.00 | 0.00 | 14.15 (total)<br>4.90 (single) |
| Fugitive Emissions (unpaved roads) | 75.32 | 19.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Total Emissions (Plant 1) | 303.36 | 138.44 | 8,710.57 | 5,462.47 | 10,359.57 | 851.53 | 1,733.4 (total)<br>761.61 (single) |
| Total Emissions (Plant 2) | -- | -- | -- | 16,910.96 | -- | -- | 573.46 (total)<br>174.77 (single) |
| Total Emissions (Plant 1 + Plant 2) | 303.36 | 138.44 | 8,710.57 | 22,373.43 | 10,359.57 | 851.53 | 2,306.86 (total)<br>936.38 (single) |
| Major Source Threshold (Part 70) | NA | 100 | 100 | 100 | 100 | 100 | 10 single<br>25 total |
| Major Source Threshold (PSD) | 100 | 100 | 100 | 100 | 100 | 100 | NA |

**Federal Rule Applicability**

(a) The Permittee shall comply with the provisions of Standards of Performance for Petroleum Refineries, which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. The one (1) no. 4 boiler, constructed in 2006, with a maximum heat input rate of 84.9 MMBtu/hr of process gas and/or No. 6 residual oil and/or natural gas, identified as B4 and exhausting to stack 131 are subject to the following requirements of 40 CFR Part 60, Subpart J:

(1) 40 CFR 60.100(a), (b), (c), (d), (e)
(2) 40 CFR 60.101
(3) 40 CFR 60.102
(4) 40 CFR 60.103

(5) 40 CFR 60.104
(6) 40 CFR 60.105(a)(1-2)(i-ii)(3)(i-iv)(4)(i-iv)(A-D)(5)(i-ii)(6)(i-ii)(7)(i-iii)(8)(i-ii)(9)(i-ii)(10)(11)(12)(i-ii)(13)(i-iii), (b)(1)(i-v)(2)(3)(i-iii), (c), (d), (e)(1-4)(i-ii)
(7) 40 CFR 60.106(a), (b)(1-3)(i-ii)(4), (c)(1-3), (d), (e)(1)(i-iii)(2), (f)(1-3), (g), (h)(1-6), (i)(1-12), (j)(1-3)(i-iii)(4)(k)(1-4)
(8) 40 CFR 60.107(a), (b)(1)(i-iii)(2-4), (c)(1)(i-iii)(2-3)(i-iv)(4)(i-vi)(5-6), (d-g)
(9) 40 CFR 60.108(a-e)
(10) 40 CFR 60.109(a), (b)(1-2)

(b) The Permittee shall comply with the provisions of Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels), which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. Storage tanks identified as Nos. 18, 24, and 175 are subject to the following requirements of 40 CFR Part 60, Subpart Kb:

(1) 40 CFR 60.110b (a), (b), (d)(1-8), (e)(i-ii), (2), (3), (4)
(2) 40 CFR 60.111b
(3) 40 CFR 60.112b (a)(1(i-ix)), (4)
(4) 40 CFR 60.113b (a)(1-5)
(5) 40 CFR 60.114b (a-d)
(6) 40 CFR 60.115b (a)
(7) 40 CFR 60.116b (a-f)
(8) 40 CFR 60.117b

(c) The Permittee shall comply with the provisions of Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. Storage tanks identified as Nos. 47 and 52 are subject to the following requirements of 40 CFR Part 60, Subpart K:

(1) 40 CFR 60.110
(2) 40 CFR 60.111
(3) 40 CFR 60.112
(4) 40 CFR 60.113

(d) Storage tanks identified as Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11A, 11B, 15, 17, 19, 21, 22, 25, 26, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 49, 48 and 50, are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Parts 60.110, 110a-115a or 110b-117b, Subparts K, Ka and Kb), because these tanks were all constructed between 1940 and 1958, prior to the earliest applicability date of June 11, 1973 for Subpart K, Ka or Kb.

(e) The Permittee shall comply with the provisions of 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, which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. Pipeline Valves - Gas, identified as 090, Pipeline Valves - Light Liquid, identified as 091, Pipeline Valves - Heavy Liquid, identified as 092, Pipeline Valves - Hydrogen, identified as 093, Open Ended Valves, identified as 094, Flanges, identified as 095, Pump Seals Light Liquid, identified as 096, Pump Seals Heavy Liquid, identified as 097, Compressor Seals - Gas, identified as 098, Compressor Seals - Heavy Liquid, identified as 099, Vessel Relief Valves, identified as 101, process units made up of vessels, piping, exchangers, identified as PENEX, equipment associated with the sampling connection system, fugitive emissions from the Hydrotreater unit, Amine Unit, Sulfur Recovery Unit, Tail Gas Treatment Unit, are subject to the following requirements of 40 CFR Part 60, Subpart GGG:

(1) 40 CFR 60.590
(2) 40 CFR 60.591
(3) 40 CFR 60.592
(4) 40 CFR 60.593

(f) The Permittee shall comply with the provisions of VOC Emissions from Petroleum Refinery Wastewater Systems (40 CFR Part 60, Subpart QQQ), which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. Two (2) sets of Oil/water Separators equipped with covers for VOC control, identified as 071 are subject to the following requirements of 40 CFR Part 60, Subpart QQQ:

(1) 40 CFR 60.690
(2) 40 CFR 60.691
(3) 40 CFR 60.692-1
(4) 40 CFR 60.692-2
(5) 40 CFR 60.692-3(a), (c), (d), (e), (f)
(6) 40 CFR 60.692-5
(7) 40 CFR 60.692-6
(8) 40 CFR 60.692-7
(9) 40 CFR 60.693-2
(10) 60 CFR 60.694
(11) 60 CFR 60.695
(12) 40 CFR 60.696(a), (c), (d)(1)(i-iii) (2)(i-ii)
(13) 40 CFR 60.697(a), (b), (c), (e)1-4, (f), (g), (h), (i), (i), (j),(k)1-2
(14) 40 CFR 60.698
(15) 40 CFR 60.699

(g) The Permittee shall comply with the provisions of Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc), which are incorporated by reference as 326 IAC 12-1-1. Nonapplicable portions of the NSPS will not be included in the permit. One (1) boiler, identified as B4 is subject to the following requirements of 40 CFR Part 60, Subpart Dc:

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.41c
(3) 40 CFR 60.42c(d), (e)(1),(g), (h)(2), (i), (j)
(4) 40 CFR 60.43c(c), (e)(1,4)
(5) 40 CFR 60.44c(a), (b), (c), (d), (g), (h)
(6) 40 CFR 60.48c(e)11,(f)(2)i-iv

Three (3) boilers identified as boiler Nos. 1, 2 and 3, constructed in 1957, 1970 and 1957, and rated at 52.0, 65.0 and 52.0 mmBtu per hour, respectively, are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60.40c, Subpart Dc) because all were constructed prior to the rule applicability date of June 9, 1989.

(h) The Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) for National Emissions Standards for Gasoline Distribution Facilities (40 CFR Part 63, Subpart R), which are incorporated by reference as 326 IAC 20-10-1. Nonapplicable portions of the NESHAP will not be included in the permit. One (1) Truck loading rack, identified as Loading Rack, is subject to the following requirements of 40 CFR Part 63, Subpart R:

(1) 40 CFR Part 63.420
(2) 40 CFR Part 63.421
(3) 40 CFR Part 63.422(a-c)
(4) 40 CFR Part 63.424
(5) 40 CFR Part 63.425(a-c), (e-h)

(6) 40 CFR Part 63.427(a-b)
(7) 40 CFR Part 63.428(b), (c), (g)(1), (h)(1-3)
(8) Table 1

(i) The Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) for National Emission Standards for Hazardous Air Pollutants for Equipment Leaks - Control Level 2 Standards (40 CFR Part 63, Subpart UUU), which are incorporated by reference as 326 IAC 20-50-1. Nonapplicable portions of the NESHAP will not be included in the permit. One (1) CCR Platformer Unit, one (1) FCCU regenerator, identified as V-5, one (1) Hydrotreating Unit Reactor charge heater (210-H-100), identified as 122, one (1) Hydrotreating Unit Reboiler Stabilizer (210-H-101), identified as 123, one (1) Tail Gas Treatment System and Sulfur Recovery System identified as 124, and one (1) Vacuum heater, identified as 200-H6 are subject to the following requirements of 40 CFR Part 63, Subpart UUU:

(1) 40 CFR 63.1560
(2) 40 CFR 63.1561
(3) 40 CFR 63.1562
(4) 40 CFR 63.1563(b), (c)1, 2i-iv, (e)
(5) 40 CFR 63.1564
(6) 40 CFR 63.1565
(7) 40 CFR 63.1566
(8) 40 CFR 63.1567
(9) 40 CFR 63.1568
(10) 40 CFR 63.1569
(11) 40 CFR 63.1570
(12) 40 CFR 63.1571
(13) 40 CFR 63.1572
(14) 40 CFR 63.1573
(15) 40 CFR 63.1574
(16) 40 CFR 63.1575
(17) 40 CFR 63.1576
(18) 40 CFR 63.1577
(19) 40 CFR 63.1578
(20) 40 CFR 63.1579
(21) Tables 1-44

(j) The Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) for National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (40 CFR 63, Subpart CC), which are incorporated by reference as 326 IAC 20-16-1. Nonapplicable portions of the NESHAP will not be included in the permit. One (1) fixed roof cone tank, identified as 22A, and one (1) Low Sulfur Gasoline (LSG) Unit are subject to the following requirements of 40 CFR Part 63, Subpart CC:

(1) 40 CFR 63.640 (a)(1,2), (c)(1-7), (d)(1-5), (e)(1-2), (f)(1-5), (g)(1-7), (h)(1-4), (i)(1-3), (j)(1-2), (k)(1-2),
(2) 40 CFR 63.641
(3) 40 CFR 63.642 (a), (c), (g)
(4) 40 CFR 63.643 (b)
(5) 40 CFR 63.644 (a)
(6) 40 CFR 63.645 (a)
(7) 40 CFR 63.646 (a)
(8) 40 CFR 63.647 (a-b)
(9) 40 CFR 63.648 (a)(1-2)
(10) 40 CFR 63.650 (a)
(11) 40 CFR 63.651 (a)
(12) 40 CFR 63.654 (a), (c), (d)(1-6), (f)

(13) Table 5
(14) Table 6

(k) The Permittee shall comply with the provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) for Benzene Waste Operations (40 CFR Part 61, Subpart FF), which are incorporated by reference as 326 IAC 14-1-1. One (1) Low Sulfur Gasoline (LSG) Unit is subject to the following requirements of 40 CFR Part 61, Subpart FF:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.342(a)
(4) 40 CFR 61.355
(5) 40 CFR 61.356(a)(b)(1)
(6) 40 CFR 61.357(a)(c)

(l) The Permittee shall comply with the provisions of Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS (40 CFR Part 60, Subpart GGGa), which are incorporated by reference as 326 IAC 12-1-1. One (1) Low Sulfur Gasoline (LSG) Unit is subject to the following requirements of 40 CFR Part 60, Subpart GGGa:

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a

(m) The Permittee shall comply with the provisions of Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS (40 CFR Part 60, Subpart Ja), which are incorporated by reference as 326 IAC 12-1-1. The LSG Reactor Charge Heater is subject to the following requirements of 40 CFR Part 60, Subpart Ja:

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(g)

**State Rule Applicability - Entire Source**

326 IAC 1-6-3 (Preventive Maintenance Plan)
The source is subject to 326 IAC 1-6-3.

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))

(a) This existing source is a major stationary source because it is one of the 28 listed source categories (i.e. petroleum refineries) under 326 IAC 2-2, and potential sulfur dioxide ($SO_2$) volatile organic compound (VOC), carbon monoxide (CO), particulate matter (PM & PM-10) and nitrogen oxide (NOx) emissions after control are greater than 100 tons per year. This rule applies to sources commencing construction after August 7, 1977. This source was constructed prior to the applicability date but potential emissions after control were greater than 100 tons per year as of August 7, 1977 as stated above. Therefore, the source was a major PSD source for purposes of determining applicability of this rule to future modifications. Each of the following emission units (CCR platformer heater, storage tanks Nos. 12, 24, 47, 53, 54, 55, 56, 58, 159, 160, 161, 162, 163, 164, 165, 166, 167, 168 and 169), constructed after August 7, 1977, has potential to emit VOC of less than 40 tons per year. Therefore, this rule does not apply.

(b) Pursuant to Significant Permit Modification (129-20112-00003), issued on March 21, 2005 and as revised by Significant Permit Modification (129-23090-00003), the input of No. 6 fuel oil to the four (4) boilers B1, B2, B3, and B4 with a maximum fuel oil sulfur content of 0.8 percent, shall be limited to 3,214.92 thousand gallons per twelve (12) consecutive month period with compliance determined at the end of each month. This usage limit is required to limit the $PM_{10}$ emissions from the boilers to less than 14.49 tons per twelve (12) consecutive month period. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

(c) Pursuant to Significant Permit Modification (129-23090-00003), issued on January 30, 2007, the input of No. 6 fuel oil to Boiler B4 shall be limited to less than 730,000 gallons (with maximum fuel oil sulfur content of 0.5%) per twelve (12) consecutive month period, with compliance determined at the end of each month. This fuel oil usage limit for boiler B4 is part of the total fuel oil usage limit of 3,214.92 thousand gallons per year for all four (4) boilers (B1, B2, B3 and B4). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

326 IAC 2-6 (Emission Reporting)

This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit under 326 IAC 2-7, Part 70 program and has the potential to emit greater than 250 tons per year of volatile organic compounds. Therefore, pursuant to this rule, in accordance with the compliance schedule specified in 326 IAC 2-6-3, the Permittee shall submit an annual emission statement by July 1 every year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)

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

326 IAC 6-5 (Fugitive Particulate Emissions Limitations)

This source is not subject to the provisions of 326 IAC 6-5. This rule applies to sources located in nonattainment areas for particulate matter or any new source of fugitive particulate matter emissions which has not received all the necessary preconstruction approvals before December 13, 1985. The source is not located in a nonattainment area and was constructed prior to the applicability date of the rule. Therefore, the requirements of 326 IAC 6-5 do not apply.

**State Rule Applicability – Individual Facilities**

326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating), the one (1) refinery fuel gas fired boiler (ID No. 1) and two (2) refinery fuel gas fired boilers (ID Nos. 2 and 3) with No. 6 fuel oil back-up, rated at 52, 65, and 52 million British thermal units per hour, respectively, are subject to the particulate matter limitations of 326 IAC 6-2. Therefore, the PM emissions from boilers B1, B2, and B3 shall be limited to 0.40, 0.25 and 0.40 pounds per MMBtu heat input, respectively based on the following equation:

$$P_T = \frac{C \times a \times h}{76.5 \times Q^{0.75} \times N^{0.25}}$$

Where: C = maximum ground level concentration (50 µg/m3, for a period not to exceed 60 min.)
Pt = maximum allowable particulate matter (PM) emitted per MMBtu heat input
Q = total source max. indirect heater input

N = Number of stacks in fuel burning operation.

a = plume rise factor (0.67, for Q < 1,000)

h = Stack height in feet. If a number of stacks of different heights exist, the average stack height to represent "N" stacks shall be calculated by weighing each stack height with its particulate matter emission rate as follows:

$$h = \frac{\sum_{i=1}^{N} H_i \times pa_i \times Q}{\sum_{i=1}^{N} pa_i \times Q}$$

Where: pa = the actual controlled emission rate in lb/mmBtu using the emission factor from AP-42 or stack test data.

Boiler 4 is not subject to the provisions of 326 IAC 6-2-3. This rule applies to facilities that existed on September 21, 1983. Boiler 4 was constructed in 2006, therefore, the requirements of 326 IAC 6-2-3 do not apply.

326 IAC 6-2-4 (Particulate Emissions Limitations for sources of indirect heating)

(a) Pursuant to 326 IAC 6-2-4 (Particulate Matter Emissions Limitations), particulate emissions from the 5.985 MMBtu/hr LSG Charge Reactor Heater shall not exceed Pt. This limitation is calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Pt = Pounds of particulate matter emitted per million Btu (lb/MMBtu) heat input.
Q = Total source maximum operating capacity rating in million Btu per hour (MMBtu/hr) heat input. (Q > 10,000 MMBtu)

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), for Q > 10,000 MMBtu, Pt shall not exceed 0.1. Therefore, particulate emissions from the 5.985 MMBtu/hr LSG Charge Reactor Heater shall be limited to 0.1 pounds per MMBtu heat input.

(b) Pursuant to 326 IAC 6-2-4 (Particulate Matter Emissions Limitations), particulate emissions from the one (1) 84.9 MMBtu/hr boiler, identified as B4, burning refinery fuel gas and No. 6 residual fuel oil as primary fuels and natural gas as secondary fuel, shall be limited to 0.25 lb/MMBtu based on the following equation :

$Pt = 1.09 / Q^{0.26}$ where: Pt = pounds of PM emitted per MMBtu heat input (lb/MMBtu)
Q = total source operating capacity (MMBtu/hr) = 253.9

$Pt = 1.09 / 253.9^{0.26} = 0.25$ lb/MMBtu

The PM emissions from the boiler B4 shall be limited to less than 0.25 lbs PM/MMBtu.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)

Emission units C-II, boilers Nos. 1, 2 and 3, V-IV, A-HI, H101, and V-III are subject to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations). The sulfur dioxide emissions from C-II, boilers Nos. 1, 2 and 3, V-IV, A-HI, H101, and V-III, when No. 6 residual fuel oil is used, shall be limited to 1.6 pounds per million British thermal units heat input. This equates to a distillate fuel oil sulfur content limit of 1.70%. Therefore, the sulfur content of the distillate fuel must be less than or equal to 1.70% in order to comply with this rule (See Appendix A for detailed calculations). Based on the information submitted, the sulfur content of the No. 6 residual fuel oil is 0.8%. Therefore, the burner combustion of No. 6 residual fuel oil complies with the rule. This rule is not applicable to other combustion units since only refinery fuel gas will be combusted.

326 IAC 7-2-1 (Sulfur Dioxide Reporting Requirements)

Pursuant to this rule, the source shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate (pounds SO2 per MMBtu), to the OAQ upon request.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements)

This bulk petroleum product storage and transfer terminal is not subject to the provision of 326 IAC 8-1-6. This rule applies to facilities located in any county constructed after January 1, 1980, which are not otherwise regulated by any other provisions of 326 IAC 8, and have potential emissions of 25 tons/year or greater. The truck loading rack is not subject to the requirements of 326 IAC 8-1-6, because it was constructed in 1958, before the rule applicability date of January 1, 1980. Storage tanks, including Tank Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11A, 11B, 15, 19, 21, 22, 25, 26, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 49, 48, 50, 51 and 52 were constructed prior to January 1, 1980, and therefore, this rule does not apply. VOC emissions from each of the Tank Nos. 12, 24, 53, 54, 55, 56, 58, 159 - 169 (constructed after the rule applicability date of January 1, 1980), are less than 25 tons/yr. Therefore the requirements of 326 IAC 8-1-6 do not apply.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)

Tank Nos. 18, 22A, 24, and 175 are subject to the requirements of 326 IAC 8-4-3 (Petroleum Liquid Storage Facilities) because they are petroleum liquid storage tanks constructed after January 1, 1980, with a capacity greater than 39,000 gallons and contain a volatile organic liquid whose true vapor pressure is greater than 1.52 pounds per square inch (psi). All other storage tanks at the source are not subject to the requirements of 326 IAC 8-4-3. Storage tanks, including Tank Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11A, 11B, 15, 19, 21, 22, 25, 26, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 49, 48, 50, 51, 52, were constructed prior to 1980 and the source is not located in an affected county. Tank Nos. 12, 53, 54, 55, 56, 58, 159, 160, 161, 162, 166, 165, 167, 168, 169, 163, 164 have a capacity less than 39,000 gallons, therefore the rule does not apply.

Pursuant to 326 IAC 8-4-3, the Permittee shall maintain records including the following:

(a) the types of volatile petroleum liquids stored;
(b) the maximum true vapor pressure; and
(c) records of the inspections.

Tank Nos. 18, 22A, 24 and 175 are in compliance with this rule, since the Permittee has maintained records of the types of volatile petroleum liquid stored, the maximum true vapor pressure of the liquid as stored, and the results of the inspections performed on the storage vessels. These records have been maintained for a period of two (2) years, and shall be made available to the IDEM, OAQ upon written request.

326 IAC 8-4-4 (Bulk Gasoline Terminals)

The Truck Loading Rack, identified as Loading Rack, is not subject to the requirements of 326 IAC 8-4-4 (Bulk Gasoline Terminals), because it was constructed (in 1958) before the rule applicability date of 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 is not located in any of the listed counties.

326 IAC 8-4-6 (Gasoline Dispensing Facilities)

The Truck Loading Rack is not subject to the requirements of 326 IAC 8-4-6 (Gasoline Dispensing Facilities), because the Truck Loading Rack does not dispense gasoline into motor vehicle fuel tanks or portable containers, is not a gasoline dispensing facility, and is not located in any of the listed counties.

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, and is not located in any of the listed counties.

326 IAC 8-6 (Organic Solvent Emission Limitations)

Plant 1 is not subject to the requirements of 326 IAC 8-6 (Organic Solvent Limitations) because it was not constructed between the applicability dates of October 7, 1974 and January 1, 1980.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties)

Plant 1 is not subject to the requirements of 326 IAC 8-7 (Specific VOC Reduction Requirements for Lake, Porter, Clark and Floyd Counties), because plant 1 is not located in one of the listed counties.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)

Plant 1 is not subject to the requirements of 326 IAC 8-9 (Volatile Organic Liquid Storage Vessels) because this source is not located in one of the listed counties.

**Insignificant Activities**

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes) the particulate emissions from the equipment listed under insignificant activities shall be limited by the following:

Interpolation and extrapolation of the data for the process weight rate in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$ where E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

**Compliance Determination and Monitoring Requirements**

Permits issued under 326 IAC 2-7 are required to ensure 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 enforce-

ment 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.

The compliance monitoring requirements applicable to this source are as follows:

The Boiler Nos. 1, 2, 3, and 4 have applicable compliance monitoring conditions as specified below:

(a) Visible emission notations of the boilers' exhaust stacks (B1, B2, B3, and B4) shall be performed once per day during normal daylight operations when each facility is in operation and burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Response to Excursions or Exceedances. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

These monitoring conditions are necessary because the four (4) boilers, must each operate properly to ensure compliance with 326 IAC 5 (Opacity Limitations), 326 IAC 6-2-3 (Particulate Emissions Limitations for Sources of Indirect Heating), and 326 IAC 2-7 (Part 70).

**Recommendation**

The staff recommends to the Commissioner that the Title V Renewal be approved. This recommendation is based on the following facts and conditions:

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 September 25, 2007.

**Conclusion**

The operation of this petroleum refinery shall be subject to the conditions of the attached Part 70 Renewal No. T129-25424-00003.

# Appendix A: Emission Calculations

## Tank VOC/HAP Emissions - Maximum PTE

**Company Name:** **Countrymark Cooperative, LLP**
**Address City IN Zip:** **1200 Refinery Road, Mount Vernon, Indiana 47620**
**Operating Permit No.:** **129-25424-00003**
**Reviewer:** **Roger Osburn**
**Date:** **3-Dec-08**

| Tank Number | Product Stored | Total VOC Tons/yr |
|---|---|---|
| 22B | Residual Fuel Oil No.6 | 0.59 |
| 173 | Residual Fuel Oil No.6 | 0.59 |
| 174 | Residual Fuel Oil No.6 | 0.59 |
| 175 | Gasoline (RVP 13) | 5.15 |
| Total | | 6.92 |

Note: Storage tank emissions are estimated using USEPA's Tanks 4.09 software program and provided by the source.

| Tank Number | Product Stored | VOC Emissions Tons/yr | HAP Emissions (TPY) | | | | | Total |
|---|---|---|---|---|---|---|---|---|
| | | | Benzene | Toluene | Ethyl-Benzene | Xylenes | n-Hexane | |
| 22B | Residual Fuel Oil No.6 | 0.59 | 0.02 | 0.04 | 0.00 | 0.02 | 0.03 | 0.68 |
| 173 | Residual Fuel Oil No.6 | 0.59 | 0.02 | 0.04 | 0.00 | 0.02 | 0.03 | 0.68 |
| 174 | Residual Fuel Oil No.6 | 0.59 | 0.02 | 0.04 | 0.00 | 0.02 | 0.03 | 0.68 |
| 175 | Gasoline (RVP 13) | 5.15 | 0.02 | 0.03 | 0.00 | 0.01 | 0.04 | 5.24 |
| Total | | 6.92 | 0.06 | 0.132 | 0.005 | 0.059 | 0.111 | 7.29 |

Note: Storage tank emissions are estimated using USEPA's Tanks 4.09 software program and provided by the source.

**Appendix A: Emissions Calculations**

**Main Refinery Flare**

**Company Name:** **Countrymark Cooperative, LLP**
**Address City IN Zip:** **1200 Refinery Road, Mount Vernon, Indiana 47620**
**Operating Permit No.:** **129-25424-00003**
**Reviewer:** **Roger Osburn**
**Date:** **3-Dec-08**

Main Refinery Flare, burning process gas, identified as RCD-1, installed in 1945 and replaced in 2006 and exhausting to stack 118

| Heat Input | Potential Throughput | Pollutant | PM* | PM10* | SO2 | NOx | VOC | CO |
|---|---|---|---|---|---|---|---|---|
| MMBtu/hr | MMCF/yr | Emission Factor in lb/MMCF | 7.6 | 7.6 | 3429.7 | 22.2 | 5.5 | 84.0 |
| 14.0 | 122.6 | Potential Emission in tons/yr | 0.47 | 0.47 | 210.31 | 1.36 | 0.34 | 5.15 |
| | | HAPs - Organics | Benzene | Dichlorobenzene | Formaldehyde | Hexane | Toluene | |
| | | Emission Factor in lb/MMcf | 2.1E-03 | 1.2E-03 | 7.5E-02 | 1.8E+00 | 3.4E-03 | |
| | | Potential Emission in tons/yr | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | |
| | | HAPs - Metals | Lead | Cadmium | Chromium | Manganese | Nickel | |
| | | Emission Factor in lb/MMcf | 5.0E-04 | 1.1E-03 | 1.4E-03 | 3.8E-04 | 2.1E-03 | |
| | | Potential Emission in tons/yr | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |

**Methodology**

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Source of Emission Factors:
Process gas: PM, PM-10, NOx, VOC, CO from AP-42, Chapter 1.4, (3/98)
SO2 from AIRS 3-06-001-06 (950 x % S)
No. 6 fuel oil: All pollutants' emission factors from AP-42, Chapter 1.3, (9/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

**Appendix A: Emission Calculations**
**Tank HAP Emissions - Maximum PTE**

**Company Name:** **Countrymark Cooperative, LLP**
**Address City IN Zip:** **1200 Refinery Road, Mount Vernon, Indiana 47620**
**Operating Permit No.:** **129-25424-00003**
**Reviewer:** **Roger Osburn**
**Date:** **3-Dec-08**

| Tank Number | Product Stored | VOC Emissions Tons/yr | Vapor Weight Percent * Benzene | Toluene | Ethyl-Benzene | Xylenes | Cyclohexane | Hexane | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Gasoline | N/A | 2.60% | 0.70% | 0.20% | 0.20% | 0.00% | 2.70% | |
| | | | HAP Emissions (tons/yr) | | | | | | |
| 22A | Fuel Oil | 1.26 | 0.033 | 0.009 | 0.003 | 0.003 | 0.000 | 0.034 | 0.08 |
| Total | | **1.26** | **0.033** | **0.009** | **0.003** | **0.003** | **0.000** | **0.034** | **0.08** |

Note: Storage tank emissions are estimated using USEPA's Tanks 4.0 software program and provided by the source.
* The vapor mass fraction was determined using USEPA's Tanks 4.0 software program using the liquid concentrations of HAPs from a Countrymark distillate sample.

**Appendix A: Emission Calculations**
**Natural Gas and Refinery Fuel Gas Combustion**
**Less than 100 MMBtu/hr**

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, Posey, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

**C. TGTU Incinerator Burner (124-2)**

| Equipment ID No. | Name | Primary Fuel Type | Back up Fuel Type | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| 520-H-161 | TGTU Incinerator Burner | Refinery Fuel Gas | Natural Gas | 1.29 |

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

**1. Refinery Fuel Gas Combustion (Primary Fuel)**

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.001 | 7.6 | 0.011 | 0.050 |
| PM10 | 0.001 | 7.6 | 0.011 | 0.050 |
| $SO_2$ * | 0.001 | 950 x %S | 0.043 | 0.187 |
| Nox | 0.001 | 100 | 0.150 | 0.656 |
| VOC | 0.001 | 5.5 | 0.008 | 0.036 |
| CO | 0.001 | 84 | 0.126 | 0.551 |
| Lead | 0.001 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.001 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.001 | 0.075 | 0.000 | 0.000 |
| Hexane | 0.001 | 1.8 | 0.003 | 0.012 |
| Napthalene | 0.001 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.001 | 0.0034 | 0.000 | 0.000 |

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SC_2$ and NOx.
* $SO_2$ emission factor is taken from EPA 450-4-90-003.
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

**2. Natural Gas Combustion (Back-up Fuel)**

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.001 | 7.6 | 0.010 | 0.042 |
| PM10 | 0.001 | 7.6 | 0.010 | 0.042 |
| $SO_2$ | 0.001 | 0.6 | 0.001 | 0.003 |
| Nox | 0.001 | 100 | 0.126 | 0.554 |
| VOC | 0.001 | 5.5 | 0.007 | 0.030 |
| CO | 0.001 | 84 | 0.106 | 0.465 |
| Lead | 0.001 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.001 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.001 | 0.075 | 0.000 | 0.000 |
| Hexane | 0.001 | 1.8 | 0.002 | 0.010 |
| Napthalene | 0.001 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.001 | 0.0034 | 0.000 | 0.000 |

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.

**Methodology** Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/to

**Appendix A: Emission Calculations**
**Natural Gas and Refinery Fuel Gas Combustion**
**Less than 100 MMBtu/hr**

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

**B. Hydrotreater Unit Stabilizer (123)**

| Equipment ID No. | Name | Primary Fuel Type | Back up Fuel Type | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| 210-H-101 | Hydrotreater Unit Stabilizer Reboiler Heater | Refinery Fuel Gas | Natural Gas | 19.94 |

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.023 | 7.6 | 0.176 | 0.771 |
| PM10 | 0.023 | 7.6 | 0.176 | 0.771 |
| $SO_2$ * | 0.023 | 950 x %S | 0.660 | 2.891 |
| NOx * | 0.023 | 0.04 | 0.798 | 3.493 |
| VOC | 0.023 | 5.5 | 0.127 | 0.558 |
| CO | 0.023 | 84 | 1.945 | 8.521 |
| Lead | 0.023 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.023 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.023 | 0.075 | 0.002 | 0.008 |
| Hexane | 0.023 | 1.8 | 0.042 | 0.183 |
| Napthalene | 0.023 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.023 | 0.0034 | 0.000 | 0.000 |

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SC_2$ and NOx.
* $SO_2$ emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.04lb/mmbtu is provided by the burner vendor
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.020 | 7.6 | 0.149 | 0.651 |
| PM10 | 0.020 | 7.6 | 0.149 | 0.651 |
| $SO_2$ | 0.020 | 0.6 | 0.012 | 0.051 |
| NOx * | 0.020 | 0.04 | 0.798 | 3.493 |
| VOC | 0.020 | 5.5 | 0.108 | 0.471 |
| CO | 0.020 | 84 | 1.642 | 7.192 |
| Lead | 0.020 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.020 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.020 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.020 | 1.8 | 0.035 | 0.154 |
| Napthalene | 0.020 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.020 | 0.0034 | 0.000 | 0.000 |

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.04 lb/mmbtu is provided by the burner vendor.

**Methodology**
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/to

**Appendix A: Emission Calculations**
**Natural Gas and Refinery Fuel Gas Combustion**
**Less than 100 MMBtu/hr**

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

**A. Hydrotreater Unit Reactor (122)**

| Equipment ID No. | Name | Primary Fuel Type | Back up Fuel Type | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| 210-H-100 | Hydrotreater Reactor Charge Heater | Refinery Fuel Gas | Natural Gas | 19.25 |

Refinery Fuel Gas Heating Value = 861 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.022 | 7.6 | 0.170 | 0.744 |
| PM10 | 0.022 | 7.6 | 0.170 | 0.744 |
| $SO_2$ * | 0.022 | 950 x %S | 0.637 | 2.791 |
| NOx * | 0.022 | 0.04 | 0.770 | 3.373 |
| VOC | 0.022 | 5.5 | 0.123 | 0.539 |
| CO | 0.022 | 84 | 1.878 | 8.226 |
| Lead | 0.022 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.022 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.022 | 0.075 | 0.002 | 0.007 |
| Hexane | 0.022 | 1.8 | 0.040 | 0.176 |
| Napthalene | 0.022 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.022 | 0.0034 | 0.000 | 0.000 |

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SC_2$ and NOx.
* $SO_2$ emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.04lb/mmbtu is provided by the burner vendor
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.019 | 7.6 | 0.143 | 0.628 |
| PM10 | 0.019 | 7.6 | 0.143 | 0.628 |
| $SO_2$ | 0.019 | 0.6 | 0.011 | 0.050 |
| NOx * | 0.019 | 0.04 | 0.770 | 3.373 |
| VOC | 0.019 | 5.5 | 0.104 | 0.455 |
| CO | 0.019 | 84 | 1.585 | 6.944 |
| Lead | 0.019 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.019 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.019 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.019 | 1.8 | 0.034 | 0.149 |
| Napthalene | 0.019 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.019 | 0.0034 | 0.000 | 0.000 |

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.04 lb/mmbtu is provided by the burner vendor.

**Methodology**
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/to

**TSD, Appendix A: Emission Calculations**
**Natural Gas and Refinery Fuel Gas Combustion**
**Less than 100 MMBtu/hr**

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

**E. FCCU Raw Oil Heater**

| Equipment ID No. | Name | Primary Fuel Type | Back up Fuel Type | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| H-101 | FCCU Pre-Heater H-101 | Refinery Fuel Gas | Natural Gas | 18.1 |

Refinery Fuel Gas Heating Value = 1000 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.018 | 7.6 | 0.138 | 0.603 |
| PM10 | 0.018 | 7.6 | 0.138 | 0.603 |
| $SO_2$ * | 0.018 | 950 x %S | 21.838 | 95.649 |
| Nox | 0.018 | 100 | 1.810 | 7.928 |
| VOC | 0.018 | 5.5 | 0.100 | 0.436 |
| CO | 0.018 | 84 | 1.520 | 6.659 |
| Lead | 0.018 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.018 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.018 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.018 | 1.8 | 0.033 | 0.143 |
| Napthalene | 0.018 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.018 | 0.0034 | 0.000 | 0.000 |

Notes:
Sulfur content of FCCU Raw Oil Heater Refinery fuel gas is 1.27% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SC_2$.
* $SO_2$ emission factor is taken from EPA 450-4-90-003.
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.018 | 7.6 | 0.135 | 0.591 |
| PM10 | 0.018 | 7.6 | 0.135 | 0.591 |
| $SO_2$ | 0.018 | 0.6 | 0.011 | 0.047 |
| Nox | 0.018 | 100 | 1.775 | 7.772 |
| VOC | 0.018 | 5.5 | 0.098 | 0.427 |
| CO | 0.018 | 84 | 1.491 | 6.529 |
| Lead | 0.018 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.018 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.018 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.018 | 1.8 | 0.032 | 0.140 |
| Napthalene | 0.018 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.018 | 0.0034 | 0.000 | 0.000 |

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

**Methodology**
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

## Appendix A: Emission Calculations

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, Posey, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

### Uncontrolled Potential Emissions (tons/year)

| | Emissions Generating Activity | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Pollutant | Combustion | Combustion | Combustion | Combustion | Combustion | Fugitives | Storage Tanks | **TOTAL** |
| | Hydrotreater Units | TGTU Incinerator Process Emissions, Burner and Unscheduled | Claus Unit Startup burner | Sour Flare Pilot | No. 6 Fuel Oil in Boilers | from components | 710T-101 and Tank 46 * | |
| | 210-H-100 and 210-H-101 | 520-H-161 and 520-H-162 | 520-H-101 | 520-H-163 | B1, B2, and B3 | | | |
| | | | | | | | | |
| PM | 1.52 | 0.05 | 0.05 | 0.03 | 14.72 | 0.00 | 0.00 | 16.37 |
| PM10 | 1.52 | 0.05 | 0.05 | 0.03 | 12.84 | 0.00 | 0.00 | 14.49 |
| SO2 | 5.68 | 11.63 | 0.00 | 0.04 | 53.30 | 0.00 | 0.00 | 70.65 |
| NOx | 6.87 | 0.66 | 0.67 | 0.40 | 66.98 | 0.00 | 0.00 | 75.57 |
| VOC | 1.10 | 0.04 | 0.04 | 0.02 | 0.04 | 1.23 | 7.57 | 10.03 |
| CO | 16.75 | 0.55 | 0.56 | 0.33 | 1.51 | 0.00 | 0.00 | 19.70 |
| total HAPs | 0.37 | 0.01 | 0.01 | 0.01 | 3.39 | 0.06 | 0.15 | 4.01 |
| single HAP | 0.359 (Hexane) | 0.012 (Hexane) | 0.012 (Hexane) | 0.007 (Hexane) | 3.243 (Hexane) | 0.025 (Hexane) | 0.057 (Hexane) | 2.059 (Hexane) |
| | | | | | | | | |
| Total emissions based on rated capacity at 8,760 hours/year. | | | | | | | | |
| * VOC emissions from Tank 46 are only one-time emissions from tank cleaning. | | | | | | | | |

** Contemporaneous decreases includes emission reductions from FCCU Pre-heater H-101, Crude Heater C-II Low-Nox burner installation, and Oil/Water separator controls.

**Appendix A: Emission Calculations**
**Natural Gas and Refinery Fuel Gas Combustion**
**Less than 100 MMBtu/hr**

**Company Name:** Countrymark Cooperative, LLP
**Address City IN Zip:** 1200 Refinery Road, Mount Vernon, IN 47620
**Title V No.:** 129-25424-00003
**Reviewer:** Roger Osburn
**Date:** 3-Dec-08

**A. Vacuum Pre-Heater (126)**

| Equipment ID No. | Name | Primary Fuel Type | Back up Fuel Type | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| 200-H6 | Vaccum Pre-Heater | Refinery Fuel Gas | Natural Gas | 5.49 |

Refinery Fuel Gas Heating Value = 767 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.007 | 7.6 | 0.054 | 0.238 |
| PM10 | 0.007 | 7.6 | 0.054 | 0.238 |
| $SO_2$ * | 0.007 | 950 x %S | 0.204 | 0.894 |
| NOx * | 0.007 | 0.1 | 0.549 | 2.405 |
| VOC | 0.007 | 5.5 | 0.039 | 0.172 |
| CO | 0.007 | 84 | 0.601 | 2.633 |
| Lead | 0.007 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.007 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.007 | 0.075 | 0.001 | 0.002 |
| Hexane | 0.007 | 1.8 | 0.013 | 0.056 |
| Napthalene | 0.007 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.007 | 0.0034 | 0.000 | 0.000 |

Notes:
Sulfur content of Refinery fuel gas is 0.03% (equal to NSPS Subpart J limit of 0.01 gr/dscf)
Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SC_2$ and NOx.
* $SO_2$ emission factor is taken from EPA 450-4-90-003 and NOx emission factor of 0.10 lb/mmbtu is provided by the burner vendor (guaranteed)
Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.005 | 7.6 | 0.041 | 0.179 |
| PM10 | 0.005 | 7.6 | 0.041 | 0.179 |
| $SO_2$ | 0.005 | 0.6 | 0.003 | 0.014 |
| NOx * | 0.005 | 0.1 | 0.549 | 2.405 |
| VOC | 0.005 | 5.5 | 0.030 | 0.130 |
| CO | 0.005 | 84 | 0.452 | 1.980 |
| Lead | 0.005 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.005 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.005 | 0.075 | 0.000 | 0.002 |
| Hexane | 0.005 | 1.8 | 0.010 | 0.042 |
| Napthalene | 0.005 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.005 | 0.0034 | 0.000 | 0.000 |

Notes:
Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.
* NOx emission factor 0.10 lb/mmbtu is provided by the burner vendor (guaranteed)

**Methodology**
Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/to

**Appendix A: Emission Calculations**
**Boiler Emission**

**Company Name:** **Countrymark Cooperative, LLP**
**Address City IN Zip:** **1200 Refinery Road, Mount Vernon, Indiana 47620**
**Renewal Permit No.:** **129-25424-00003**
**Reviewer:** **Roger Osburn**
**Date:** **3-Dec-08**

| | | |
|---|---|---|
| Maximum Steam Producing Rate | 70,000 | lb/hr |
| Maximum Water Feed Rate | 70,000 | lb/hr |
| Btu required to convert water to steam | 970 | Btu/lb steam |
| Boiler Efficiency | 80.00% | % |

Maximum Required Heat Input = $\frac{70000 \text{ lb}}{\text{hr}} \times \frac{970 \text{ Btu}}{\text{lb of steam}} \times \frac{1.0 \text{ lb steam input}}{0.8 \text{ lb steam output}}$

= 84875000 Btu/hr
= 84.875 mmBTU/hr

**No.6 Fuel Oil:**

No.6 Fuel oil is limited 3,214,290 gallons per twelve consecutive months and 0.5% Sulfur content based on NSPS (Subpart Dc).

| | | | |
|---|---|---|---|
| Maximum Fuel Oil Flow | = | 1,000,000 | Gallons/yr |
| | = | 115.34 | Gallons/hr |
| | = | 0.115 | 1000 Gallons/hr |

**Natural Gas:**

| | | | |
|---|---|---|---|
| Heat Content | = | 1020 | Btu/cu.ft |
| Fuel Feed Rate | = | 83210.78 | cu.ft/hr |
| | = | 0.083 | mmcu.ft/hr |

**Refinery Fuel Gas:**

| | | | |
|---|---|---|---|
| Heat Content | = | 1000 | Btu/cu.ft |
| Fuel Feed Rate | = | 84875.00 | cu.ft/hr |
| | = | 0.085 | mmcu.ft/hr |

**No.6 Fuel Oil Combustion**

| Pollutant | Maximum rate, thousand gal/hr | Emission Factor, lb/1000gallons | Emission Rate, lb/hr | Maximum Uncontrolled Emissions, ton/yr | Pollution Control Efficiency, % | Maximum Controlled Emissions, ton/yr |
|---|---|---|---|---|---|---|
| PM | 0.115 | 9.6 | 1.1073 | 4.850 | 0 | 4.850 |
| PM10 | 0.115 | 9.07 | 1.0461 | 4.582 | 0 | 4.582 |
| $SO_2$ | 0.115 | 157 x %S | 9.0542 | 39.657 | 0 | 39.657 |
| NOx | 0.115 | 55 | 6.3437 | 27.785 | 0 | 27.785 |
| VOC | 0.115 | 0.28 | 0.0323 | 0.141 | 0 | 0.141 |
| CO | 0.115 | 5 | 0.5767 | 2.526 | 0 | 2.526 |
| Lead | 0.115 | 0.0005 | 0.0001 | 0.000 | 0 | 0.000 |
| Benzene | 0.115 | 0.0021 | 0.0002 | 0.001 | 0 | 0.001 |
| Formaldehyde | 0.115 | 0.075 | 0.0087 | 0.038 | 0 | 0.038 |
| Hexane | 0.115 | 1.8 | 0.2076 | 0.909 | 0 | 0.909 |
| Naphthalene | 0.115 | 0.00061 | 0.0001 | 0.000 | 0 | 0.000 |
| Toluene | 0.115 | 0.0034 | 0.0004 | 0.002 | 0 | 0.002 |

Emission Factor Source - AP42 Section 1.3, 9/98

**Appendix A: Emission Calculations**
**Boiler Emission**
**Company Name: Countrymark Cooperative, LLP**
**Address City IN Zip: 1200 Refinery Road, Mount Vernon, Indiana 47620**
**Renewal Permit No.: 129-25424-00003**
**Reviewer: Roger Osburn**
**Date: 3-Dec-08**

Sulfur Content of Boiler Refinery Fuel Gas - 0.03% (Subject to NSPS Subpart J limit of 0.01 gr/dscf)

| Pollutant | Maximum rate, mmcf/hr | Emission Factor, lb/mmcf | Emission Rate, lb/hr | Maximum Uncontrolled Emissions, ton/yr | Pollution Control Efficiency, % | Maximum Controlled Emissions, ton/yr |
|---|---|---|---|---|---|---|
| PM | 0.085 | 7.6 | 0.6451 | 2.825 | 0 | 2.825 |
| PM10 | 0.085 | 7.6 | 0.6451 | 2.825 | 0 | 2.825 |
| $SO_2$ | 0.085 | 950 x %S | 2.4189 | 10.595 | 0 | 10.595 |
| NOx | 0.085 | 50 | 4.2438 | 18.588 | 0 | 18.588 |
| VOC | 0.085 | 5.5 | 0.4668 | 2.045 | 0 | 2.045 |
| CO | 0.085 | 84 | 7.1295 | 31.227 | 0 | 31.227 |
| Lead | 0.085 | 0.0005 | 0.0000 | 0.000 | 0 | 0.000 |
| Benzene | 0.085 | 0.0021 | 0.0002 | 0.001 | 0 | 0.001 |
| Formaldehyde | 0.085 | 0.075 | 0.0064 | 0.028 | 0 | 0.028 |
| Hexane | 0.085 | 1.8 | 0.1528 | 0.669 | 0 | 0.669 |
| Naphthalene | 0.085 | 0.00061 | 0.0001 | 0.000 | 0 | 0.000 |
| Toluene | 0.085 | 0.0034 | 0.0003 | 0.001 | 0 | 0.001 |

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion, except $SO_2$ EPA 450/4-90-003. Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

**Natural Gas Combustion (Back-up Fuel)**

| Pollutant | Maximum rate, mmcf/hr | Emission Factor, lb/mmcf | Emission Rate, lb/hr | Maximum Uncontrolled Emissions, ton/yr | Pollution Control Efficiency, % | Maximum Controlled Emissions, ton/yr |
|---|---|---|---|---|---|---|
| PM | 0.083 | 7.6 | 0.6324 | 2.770 | 0 | 2.770 |
| PM10 | 0.083 | 7.6 | 0.6324 | 2.770 | 0 | 2.770 |
| $SO_2$ | 0.083 | 0.6 | 0.0499 | 0.219 | 0 | 0.219 |
| NOx | 0.083 | 50 | 4.1605 | 18.223 | 0 | 18.223 |
| VOC | 0.083 | 5.5 | 0.4577 | 2.005 | 0 | 2.005 |
| CO | 0.083 | 84 | 6.9897 | 30.615 | 0 | 30.615 |
| Lead | 0.083 | 0.0005 | 0.0000 | 0.000 | 0 | 0.000 |
| Benzene | 0.083 | 0.0021 | 0.0002 | 0.001 | 0 | 0.001 |
| Formaldehyde | 0.083 | 0.075 | 0.0062 | 0.027 | 0 | 0.027 |
| Hexane | 0.083 | 1.8 | 0.1498 | 0.656 | 0 | 0.656 |
| Naphthalene | 0.083 | 0.00061 | 0.0001 | 0.000 | 0 | 0.000 |
| Toluene | 0.083 | 0.0034 | 0.0003 | 0.001 | 0 | 0.001 |

Emission Factor Source - AP-42 Section 1.4-7 Natural Gas Combustion.

**Worst Case Boiler Summary**

| Pollutant | Emission Rate, lb/hr | Maximum Uncontrolled Emissions, ton/yr | Pollution Control Efficiency, % | Maximum Controlled Emissions, ton/yr |
|---|---|---|---|---|
| PM | 3.5591 | 15.589 | 0 | 4.850 |
| PM10 | 3.3626 | 14.728 | 0 | 4.582 |
| $SO_2$ | 46.5646 | 203.953 | 0 | 39.657 |
| NOx | 20.3905 | 89.311 | 0 | 27.785 |
| VOC | 0.4668 | 2.045 | 0 | 2.045 |
| CO | 7.1295 | 31.227 | 0 | 31.227 |
| Lead | 0.0002 | 0.001 | 0 | 0.000 |
| Benzene | 0.0008 | 0.003 | 0 | 0.001 |
| Formaldehyde | 0.0278 | 0.122 | 0 | 0.038 |
| Hexane | 0.6673 | 2.923 | 0 | 0.909 |
| Naphthalene | 0.0002 | 0.001 | 0 | 0.000 |
| Toluene | 0.0013 | 0.006 | 0 | 0.002 |

**Appendix A: Emission Calculations**

**Natural Gas and Refinery Fuel Gas Combustion**

**Less than 100 MMBtu/hr**

**Company Name: Countrymark Cooperative, LLP**

**Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620**

**Renewal Permit No.: 129-25424-00003**

**Reviewer: Roger Osburn**

**Date: 3-Dec-08**

**E. FCCU Raw Oil Heater**

| Equipment ID No. | Name | Primary Fuel Typ | ack up Fuel Typ | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| | | | | |
| H-101 | FCCU Pre-Heater H-101 | Refinery Fuel Ga | Natural Gas | 18.1 |

Refinery Fuel Gas Heating Value = 1000 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| | | | | |
| PM | 0.018 | 7.6 | 0.138 | 0.603 |
| PM10 | 0.018 | 7.6 | 0.138 | 0.603 |
| $SO_2$ * | 0.018 | 950 x %S | 21.838 | 95.649 |
| Nox | 0.018 | 100 | 1.810 | 7.928 |
| VOC | 0.018 | 5.5 | 0.100 | 0.436 |
| CO | 0.018 | 84 | 1.520 | 6.659 |
| Lead | 0.018 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.018 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.018 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.018 | 1.8 | 0.033 | 0.143 |
| Napthalene | 0.018 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.018 | 0.0034 | 0.000 | 0.000 |

Notes:

Sulfur content of Crude Heater Refinery fuel gas is 1.27% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)

Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SO_2$.

* $SO_2$ emission factor is taken from EPA 450-4-90-003.

Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.018 | 7.6 | 0.135 | 0.591 |
| PM10 | 0.018 | 7.6 | 0.135 | 0.591 |
| $SO_2$ | 0.018 | 0.6 | 0.011 | 0.047 |
| Nox | 0.018 | 100 | 1.775 | 7.772 |
| VOC | 0.018 | 5.5 | 0.098 | 0.427 |
| CO | 0.018 | 84 | 1.491 | 6.529 |
| Lead | 0.018 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.018 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.018 | 0.075 | 0.001 | 0.006 |
| Hexane | 0.018 | 1.8 | 0.032 | 0.140 |
| Napthalene | 0.018 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.018 | 0.0034 | 0.000 | 0.000 |

Notes:

Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

**Methodology**

Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

**Appendix A: Emission Calculations**

**Natural Gas and Refinery Fuel Gas Combustion**

**Less than 100 MMBtu/hr**

**Company Name: Countrymark Cooperative, LLP**

**Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620**

**Renewal Permit No.: 129-25424-00003**

**Reviewer: Roger Osburn**

**Date: 3-Dec-08**

**D. Crude Heater C-II Low-NOx Burners Installation**

| Equipment ID No. | Name | Primary Fuel Typ | ack up Fuel Typ | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| | | | | |
| C-II | Crude Heater C II | Refinery Fuel Ga | Natural Gas | 131 |

Refinery Fuel Gas Heating Value = 1000 BTU/Scf; Natural Gas Heating Value = 1020 BTU/Scf

1. Refinery Fuel Gas Combustion (Primary Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| | | | | |
| PM | 0.131 | 7.6 | 0.996 | 4.361 |
| PM10 | 0.131 | 7.6 | 0.996 | 4.361 |
| $SO_2$ * | 0.131 | 950 x %S | 601.716 | 2635.515 |
| NOx * | 0.131 | 0.08 | 10.480 | 45.902 |
| VOC | 0.131 | 5.5 | 0.721 | 3.156 |
| CO | 0.131 | 84 | 11.004 | 48.198 |
| Lead | 0.131 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.131 | 0.0021 | 0.000 | 0.001 |
| Formaldehyde | 0.131 | 0.075 | 0.010 | 0.043 |
| Hexane | 0.131 | 1.8 | 0.236 | 1.033 |
| Napthalene | 0.131 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.131 | 0.0034 | 0.000 | 0.002 |

Notes:

Sulfur content of Crude Heater Refinery fuel gas is 4.835% (not subject to NSPS Subpart J limit of 0.01 gr/dscf)

Refinery fuel gas emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except $SO_2$ and NOx.

* $SO_2$ emission factor is taken from EPA 450-4-90-003 and NOx emission factor 0.08 lb/mmbtu is provided by the burner vendor.

Refinery fuel gas HAP emission factors assumed to be the same as natural gas.

2. Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| | | | | |
| PM | 0.128 | 7.6 | 0.976 | 4.275 |
| PM10 | 0.128 | 7.6 | 0.976 | 4.275 |
| $SO_2$ | 0.128 | 0.6 | 0.077 | 0.338 |
| NOx * | 0.128 | 0.06 | 7.860 | 34.427 |
| VOC | 0.128 | 5.5 | 0.706 | 3.094 |
| CO | 0.128 | 84 | 10.788 | 47.252 |
| Lead | 0.128 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.128 | 0.0021 | 0.000 | 0.001 |
| Formaldehyde | 0.128 | 0.075 | 0.010 | 0.042 |
| Hexane | 0.128 | 1.8 | 0.231 | 1.013 |
| Napthalene | 0.128 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.128 | 0.0034 | 0.000 | 0.002 |

Notes:

Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion, except NOx.

* NOx emission factor 0.06 lb/mmbtu is provided by the burner vendor.

**Methodology**

Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

**Appendix A: Emission Calculations**

**Natural Gas and Refinery Fuel Gas Combustion**

**Less than 100 MMBtu/hr**

**Company Name: Countrymark Cooperative, LLP**

**Address City IN Zip: 1200 Refinery Road, Mount Vernon, Posey, IN 47620**

**Renewal Permit No.: 129-25424-00003**

**Reviewer: Roger Osburn**

**Date: 3-Dec-08**

**F. Claus Unit Startup Burner (124-1)**

| Equipment ID No. | Name | Primary Fuel Typ | ack up Fuel Typ | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| | | | | |
| 520-H-101 | Claus Startup Burner | Natural Gas | None | 1.56 |

Natural Gas Heating Value = 1020 BTU/Scf

Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.002 | 7.6 | 0.012 | 0.051 |
| PM10 | 0.002 | 7.6 | 0.012 | 0.051 |
| $SO_2$ | 0.002 | 0.6 | 0.001 | 0.004 |
| Nox | 0.002 | 100 | 0.153 | 0.670 |
| VOC | 0.002 | 5.5 | 0.008 | 0.037 |
| CO | 0.002 | 84 | 0.128 | 0.563 |
| Lead | 0.002 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.002 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.002 | 0.075 | 0.000 | 0.001 |
| Hexane | 0.002 | 1.8 | 0.003 | 0.012 |
| Napthalene | 0.002 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.002 | 0.0034 | 0.000 | 0.000 |

Notes:

Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

**G. Sour Flare Pilot**

| Equipment ID No. | Name | Primary Fuel Typ | ack up Fuel Typ | Maximum Heat Input Rate (MMBtu/hr) |
|---|---|---|---|---|
| | | | | |
| 520-H-163 | Sour Flare Pilot | Natural Gas | None | 0.92 |

Natural Gas Heating Value = 1020 BTU/Scf

Natural Gas Combustion (Back-up Fuel)

| Pollutant | Maximum Rate (MMcf/hr) | Emission Factor (lb/MMcf) | Emission Rate (lb/hr) | Maximum Uncontrolled Emissions (tons/yr) |
|---|---|---|---|---|
| PM | 0.001 | 7.6 | 0.007 | 0.030 |
| PM10 | 0.001 | 7.6 | 0.007 | 0.030 |
| $SO_2$ | 0.001 | 0.6 | 0.001 | 0.002 |
| Nox | 0.001 | 100 | 0.090 | 0.395 |
| VOC | 0.001 | 5.5 | 0.005 | 0.022 |
| CO | 0.001 | 84 | 0.076 | 0.332 |
| Lead | 0.001 | 0.0005 | 0.000 | 0.000 |
| Benzene | 0.001 | 0.0021 | 0.000 | 0.000 |
| Formaldehyde | 0.001 | 0.075 | 0.000 | 0.000 |
| Hexane | 0.001 | 1.8 | 0.002 | 0.007 |
| Napthalene | 0.001 | 0.00061 | 0.000 | 0.000 |
| Toluene | 0.001 | 0.0034 | 0.000 | 0.000 |

Notes: Natural gas combustion emission factors are taken from AP-42 Section 1.4-7 Natural Gas Combustion.

**Methodology**

Emission (tons/yr) = Throughput (MMCF/hr) x 8760 (hr/yr) x Emission Factor (lb/MMCF) / 2,000 lb/ton

# INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

*Mitchell E. Daniels Jr.*
**Governor**

*Thomas W. Easterly*
**Commissioner**

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(317) 232-8603
Toll Free (800) 451-6027
**www.idem.IN.gov**


**SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED**

TO: Jim Pankey
Countrymark Cooperative, LLP
1200 Refinery Rd
Mount Vernon, IN 47620

DATE: July 1, 2010

FROM: Matt Stuckey, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Title V - Renewal
129-25424-00003

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
Matthew Smorch (Refinery Manager)
Patricia Sorenson (ERM)
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**
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Toll Free (800) 451-6027
**www.idem.IN.gov**

July 1, 2010

TO: Alexandrian Public Library

From: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

**Applicant Name: Countrymark Cooperative, LLP**
**Permit Number: 129-25424-00003**

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 11/30/07

**INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT**
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*Mitchell E. Daniels Jr.*
**Governor**

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**Commissioner**

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
**www.idem.IN.gov**

TO: Interested Parties / Applicant

DATE: July 1, 2010

RE: Countrymark Cooperative, LLP / 129-25424-00003 & 129-25574-00037

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

If you would like to request a paper copy of the permit document, please contact IDEM's central file room at:

Indiana Government Center North, Room 1201
100 North Senate Avenue, MC 50-07
Indianapolis, IN 46204
Phone: 1-800-451-6027 (ext. 4-0965)
Fax (317) 232-8659

**Please Note:** *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

# Mail Code 61-53

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| 1 | | Jim Pankey Countrymark Cooperative, LLP 1200 Refinery Rd Mount Vernon IN 47620 (Source CAATS) via confirmed delivery | | | | | | | | | |
| 2 | | Matthew L Smorch Refinery Manager Countrymark Cooperative, LLP 1200 Refinery Rd Mount Vernon IN 47620 *(RO CAATS)* | | | | | | | | | |
| 3 | | Mr. Charles L. Berger Berger & Berger, Attorneys at Law 313 Main Street Evansville IN 47700 *(Affected Party)* | | | | | | | | | |
| 4 | | Mr. Randy Brown Plumbers & Steam Fitters Union, Local 136 2300 St. Joe Industrial Park Dr Evansville IN 47720 *(Affected Party)* | | | | | | | | | |
| 5 | | Ms. Patricia Sorensen Environmental Resources Management (ERM) 11350 North Meridian Street, Ste 220 Carmel IN 46032 *(Consultant)* | | | | | | | | | |
| 6 | | Posey County Commissioners County Courthouse, 126 E. 3rd Street Mount Vernon IN 47620 *(Local Official)* | | | | | | | | | |
| 7 | | Posey County Health Department 126 E. 3rd St, Coliseum Bldg Mount Vernon IN 47620-1811 *(Health Department)* | | | | | | | | | |
| 8 | | Mount Vernon City Council and Mayors Office 520 Main Street Mount Vernon IN 47620 *(Local Official)* | | | | | | | | | |
| 9 | | Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 *(Affected Party)* | | | | | | | | | |
| 10 | | Mr. Don Mottley Save Our Rivers 6222 Yankeetown Hwy Boonville IN 47601 *(Affected Party)* | | | | | | | | | |
| 11 | | Alexandrian Public Library 115 West 5th Mt. Vernon IN 47620 *(Library)* | | | | | | | | | |
| 12 | | Mrs. Connie Parkinson 510 Western Hills Dr. Mt. Vernon IN 47620 *(Affected Party)* | | | | | | | | | |
| 13 | | Robert Hess c/o Mellon Corporation 830 Post Road East, Suite 105 Westport CT 06880 (Affected Party) | | | | | | | | | |
| 14 | | Juanita Burton 7911 W. Franklin Road Evansville IN 47712 *(Affected Party)* | | | | | | | | | |
| 15 | | Mr. John Blair 800 Adams Ave Evansville IN 47713 *(Affected Party)* | | | | | | | | | |

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