

March 21, 2002

Mr. Steve Ubelhoer
Gladieux Processing, LLC
4133 New Haven Avenue
Fort Wayne, Indiana 46803

Re: Registered Construction and Operation Status,
069-12935-00042

Dear Mr. Ubelhoer:

The application from Gladieux Processing, LLC and Gladieux trading and Marketing Company L.P. received on November 6, 2000, has been reviewed. Based on the data submitted and the provisions in 326 IAC 2-5.5, it has been determined that the following petroleum processing facility and tank terminal and processing plant, located at 4761 North US 24 East and 4757 North US 24 East, Huntington, Indiana, 46750-9617 is classified as registered.

Gladieux Processing, LLC is collocated with Gladieux Trading and Marketing Company L. P. Gladieux Processing, LLC consists of the following permitted emission units and pollution control devices:

- (a) Two (2) recovery oil storage tanks, identified as TK-41 and TK-42, each having a tank capacity of 41,460 gallons. Both tanks were constructed in 1993.
- (b) One (1) residual oil storage tank, identified as TK-43, having a tank capacity of 24,536 gallons. This tank was constructed in 1982.
- (c) One (1) naphtha storage tank, identified as TK-44, having a tank capacity of 22,750 gallons. This tank was constructed in 1982.
- (d) One (1) recovery oil storage tank, identified as TK-45, having a tank capacity of 19,433 gallons. This tank was constructed in 1975.
- (e) One (1) process heater fueled by natural gas, identified as H-201, having a maximum heat input capacity of 8.4 million Btu per hour. This process heater was constructed in 1992 and it is used as a direct heater.
- (f) One (1) process heater fueled by natural gas and petroleum distillate, identified as H-301, having a maximum heat input capacity of 8 million Btu per hour of natural gas and 8 million Btu per hour of petroleum distillate, for a total of 16 million Btu per hour. This process heater was constructed in 1993 and it is used as a direct heater.

Gladieux Trading and Marketing Company L. P. consists of the following permitted emission units and pollution control devices:

- (a) Two (2) Jet-A (kerosene) storage tanks, identified as 502 and 506. Tank 502 has a tank capacity of 451, 246 gallons and was constructed in 1958. Tank 506 has a tank capacity of 1,015,299 gallons and was constructed in 1958.
- (b) Two (2) Naphtha storage tanks, identified as 503 and 505. Tank 503 has a tank capacity of 1,015,299 gallons and was constructed in 1958. Tank 505 has a tank capacity of 451,246 gallons and was constructed in 1958.
- (c) One (1) #2 fuel oil storage tank, identified as 501, with a tank capacity of 2,284,428 gallons and was constructed in April of 1978.
- (d) One (1) Transmix storage tank, identified as 504, with a tank capacity of 2,284,438 gallons and was constructed in 1958.

The following conditions shall be applicable:

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:
 - (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 15 minutes (60 readings) in a 6-hour period 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.
2. Pursuant to 326 IAC 8-4-3 Petroleum Liquid Storage Facilities the following shall be applicable to tanks TK-41, TK-42, 503, 504 and 505:
 - (a) No owner or operator of an affected fixed roof tank shall permit use of such facility unless:
 - (1) The facility has been retrofitted 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 retrofitted with equally effective alternative control which has been approved.
 - (2) The facility is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials.
 - (3) All openings, except stub drains, are equipped with covers, lids, or seals such that:
 - (A) The cover, lid, or seal is in the closed position at all times except when in actual use;
 - (B) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;
 - (C) 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.

3. Pursuant to 326 IAC 12 and 40 CFR 60.116b, Subpart Kb (Monitoring of Operations) the following shall be applicable to storage tanks TK-41 and TK-42:
- (a) The Permittee 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 Permittee of each storage vessel as specified in 40 CFR 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. Each storage vessel with a design capacity less than 75 m³ is subject to no provision of this subpart other than those required by this paragraph.
 - (c) Except as provided in paragraphs (f) and (g) of this section, the Permittee of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.
 - (d) Except as provided in paragraph (g) of this section, the Permittee of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.
 - (e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 - (1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.
 - (2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - (A) 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 40 CFR 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).

- (B) 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:
 - (A) May be obtained from standard reference texts, or
 - (B) Determined by ASTM Method D2879-83 (incorporated by reference--see 40 CFR 60.17); or
 - (C) Measured by an appropriate method approved by the Administrator; or
 - (D) Calculated by an appropriate method approved by the Administrator.
- (f) The Permittee 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 40 CFR 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:
 - (A) ASTM Method D2879-83 (incorporated by reference--see 40 CFR 60.17); or
 - (B) ASTM Method D323-82 (incorporated by reference--see 40 CFR 60.17); or
 - (C) As measured by an appropriate method as approved by the Administrator.
- (g) The Permittee of each vessel equipped with a closed vent system and control device meeting the specifications of 40 CFR 60.112b is exempt from the requirements of paragraphs (c) and (d) of this section.

This registration is a revised registration issued to this source. The source may operate according to 326 IAC 2-5.5.

An authorized individual shall provide an annual notice to the Office of Air Quality that the source is in operation and in compliance with this registration pursuant to 326 IAC 2-5.5-4(a)(3). The annual notice shall be submitted to:

**Compliance Branch
Office of Air Quality
100 North Senate Avenue
P.O. Box 6015**

Indianapolis, IN 46206-6015

no later than March 1 of each year, with the annual notice being submitted in the format attached.

An application or notification shall be submitted in accordance with 326 IAC 2 to the Office of Air Quality (OAQ) if the source proposes to construct new emission units, modify existing emission units, or otherwise modify the source.

Sincerely,
Original signed by
Paul Dubenetzky, Chief
Permits Branch
Office of Air Quality

ERG/AR

cc: File - Huntington County
Huntington County Health Department
Air Compliance - Ryan Hillman
Indianapolis Office
Permit Tracking - Janet Mobley
Technical Support and Modeling - Michele Boner
Compliance Branch - Karen Nowak

Registration

This form should be used to comply with the notification requirements under 326 IAC 2-5.5-4(a)(3)

Company Name:	Gladieux Processing, LLC
Address:	4761 North US 24 East
City:	Huntington, IN 46750-9617
Authorized individual:	Steve Ubelhoer
Phone #:	(219) 356-1700
Registration #:	069-12935-00042

I hereby certify that Gladieux Processing, LLC is still in operation and is in compliance with the requirements of Registration 069-12935-00042.

Name (typed):
Title:
Signature:
Date:

March 21, 2002

**Indiana Department of Environmental Management
Office of Air Quality**

Technical Support Document (TSD) for a Registration

Source Background and Description

Source Name: Gladieux Processing, LLC
Source Location: 4761 North US 24 East, Huntington, IN 46750-9617
County: Huntington
SIC Code: 7389 and 5171
Operation Permit No.: 069-12935-00042
Permit Reviewer: ERG/AR

The Office of Air Quality (OAQ) has reviewed an application from Gladieux Processing, LLC relating to the operation of a petroleum processing facility.

Permitted Emission Units and Pollution Control Equipment

Gladieux Processing, LLC is collocated with Gladieux Trading and Marketing Company L. P. Gladieux Processing, LLC consists of the following permitted emission units and pollution control devices:

- (a) Two (2) recovery oil storage tanks, identified as TK-41 and TK-42, each having a tank capacity of 41,460 gallons. Both tanks were constructed in 1993.
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- (f) One (1) process heater fueled by natural gas and petroleum distillate, identified as H-301, having a maximum heat input capacity of 8 million Btu per hour of natural gas and 8 million Btu per hour of petroleum distillate, for a total of 16 million Btu per hour. This process heater was constructed in 1993 and it is used as a direct heater.

Gladieux Trading and Marketing Company L. P. consists of the following permitted emission units and pollution control devices:

- (a) Two (2) Jet-A (kerosene) storage tanks, identified as 502 and 506. Tank 502 has a tank

capacity of 451, 246 gallons and was constructed in 1958. Tank 506 has a tank capacity of 1,015,299 gallons and was constructed in 1958.

- (b) Two (2) Naphtha storage tanks, identified as 503 and 505. Tank 503 has a tank capacity of 1,015,299 gallons and was constructed in 1958. Tank 505 has a tank capacity of 451,246 gallons and was constructed in 1958.
- (c) One (1) #2 fuel oil storage tank, identified as 501, with a tank capacity of 2,284,428 gallons and was constructed in April of 1978.
- (d) One (1) Transmix storage tank, identified as 504, with a tank capacity of 2,284,438 gallons and was constructed in 1958.

* Note: The emission units associated with Gladieux Trading and Marketing have not been included in any previous permits but their emissions are at exemption levels.

Unpermitted Emission Units and Pollution Control Equipment

There are no unpermitted facilities operating at this source during this review process.

New Emission Units and Pollution Control Equipment Receiving Prior Approval

There are no new construction activities included in this permit.

Existing Approvals

The source has been operating under previous approvals including, but not limited to, the following:

- (a) CP 069-4905-00042, issued on November 13, 1995; and
- (b) OP 069-3172-00042, issued on December 7, 1993.

Source Determination

All conditions from previous approvals were incorporated into this permit.

- (a) Plant 1 Gladieux Trading and Marketing, Company L. P., the primary operation, is located at, 4757 North US 24 East, Huntington, Indiana 46750; and
- (b) Plant 2 Gladieux Processing, LLC, the supporting operation, is located at 4761 North US 24 East, Huntington, Indiana 46750

IDEM has determined that Plant 1 Gladieux Trading and Marketing Company L. P. and Plant 2 Gladieux Processing, LLC are under the common control of Gladieux Trading and Marketing Company L.P. These two plants are considered one source due to the fact that more than 50% of Gladieux Processing Product is used at the Gladieux Trading and Marketing Company L. P.. Therefore, the term "source" in the documents refers to both Gladieux Trading and Marketing Company L. P. and Gladieux Processing, LLC as one source.

Enforcement Issue

There are no enforcement actions pending.

Recommendation

The staff recommends to the Commissioner that the operation be approved. This recommendation is based on the following facts and conditions:

- (a) Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.
- (b) An application for the purposes of this review was received on November 6, 2000, with additional information received on June 27, 2001, August 13, 2001, and November 5, 2001.

Emission Calculations

See Appendix A of this document for detailed emissions calculations (pages 1 through 5 in Appendix A) (pages 1 through 15 in Appendix B) (pages 1 through 20 in Appendix C).

Potential To Emit of Source Before Controls

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency.”

Pollutant	Potential To Emit (tons/year)
PM	1.3
PM-10	1.3
SO ₂	14.2
VOC	15.4
CO	5.6
NO _x	13.7

* Total emission from both facilities.

HAP's	Potential To Emit (tons/year)
Hexane	0.07
TOTAL	0.14

* Total emissions from both facilities.

- (a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of criteria pollutants is less than 100 tons per year. Therefore, the source is not subject to the provisions of 326 IAC 2-7.
- (b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of criteria pollutants is less than 25 tons per year. Therefore, the source is not subject to the provisions of 326 IAC 2-6.1.
- (c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of pollutants are greater than levels listed in 326 IAC 2-1.1-3(d)(1), therefore the source is subject to the provisions of 326 IAC 2-5.5.1.
- (d) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is less than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, the source is

not subject to the provisions of 326 IAC 2-7.

- (e) Fugitive Emissions
This type of operation is not one of the twenty-eight (28) listed source categories under 326 IAC 2-2.

County Attainment Status

The source is located in Huntington County.

Pollutant	Status
PM-10	Attainment
SO ₂	Attainment
NO ₂	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

- (a) Volatile organic compounds (VOC) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Huntington County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.
- (b) Huntington County has been classified as attainment or unclassifiable for all criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

This existing source is not a major stationary source because no attainment regulated pollutant is emitted at a rate of 250 tons per year or more, and it is not in one of the 28 listed source categories.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This source is not subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

- (a) each criteria pollutant is less than 100 tons per year,
- (b) a single hazardous air pollutant (HAP) is less than 10 tons per year, and
- (c) any combination of HAPs is less than 25 tons/year.

This status is based on all the air approvals issued to the source.

Federal Rule Applicability

- (a) Storage tanks, TK-43 and TK-44, are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Ka), because even though the tanks were built after May 18, 1978 and prior to July 23, 1984, the tanks do not have a capacity greater than 40,000 gallons. Storage tanks, TK-41 and TK-42, have capacities greater than 40,000 gallons, but the tanks were built after July 23, 1984 therefore, 40 CFR 60, Subpart Ka does not apply. Storage tank TK-45 was built before May 18, 1978 and it has a capacity less

than 40,000 gallons therefore, 40 CFR 60, Subpart Ka does not apply. Storage tanks 501, 502, 503, 504, 505 and 506 are not subject to Subpart Ka because they were all constructed prior to May 18, 1978.

- (b) Storage tanks, TK-41 and TK-42 are subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Kb), because the tanks both have capacities greater than 40 cubic meters (m³) and the were constructed after July 23, 1984. Storage tanks, TK-43, TK-44, TK-45, 501, 502, 503, 504, 505 and 506 are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Kb), because these tanks were constructed prior to July 23, 1984.
- (c) This source is not subject to the New Source Performance Standard, 326 IAC 12, 40 CFR 60, Subpart J), because this source is not a petroleum refinery. This source does not engage 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.
- (d) Process Heaters, H-201 and H-301 are not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Db), because these process heaters are not considered steam generating units..
- (e) This source is not subject to the requirements of the National Emission Standards of Hazardous Air Pollutants (NESHAPs), Subpart CC because this source is not a petroleum refinery.

State Rule Applicability - Entire Source

326 IAC 2-6 (Emission Reporting)

This source is located in Huntington County and the potential to emit CO, VOC, NOx, PM10, and SO₂ is less than one hundred (100) tons per year. Therefore, 326 IAC 2-6 does not apply.

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 this permit:

- (a) Opacity shall not exceed an average of forty percent (40%) 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.

State Rule Applicability - Individual Facilities

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))

The operation of this petroleum processing facility will emit less than 10 tons per year of a single HAP or 25 tons per year of a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 6-2-4 (Particulate Emissions Limitations for Sources of Indirect Heating)

Process Heaters H-201 and H-301 are not subject to 326 IAC 6-2-4 (Particulate Emissions Limitations for Sources of Indirect Heating) because these units directly heat oil prior to the condensation unit. Therefore, they are not a source of indirect heating.

326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations)

Process Heaters H-201 and H-301 are not subject to this rule because both heaters have a potential to emit of less than 25 tons per year of sulfur dioxide.

326 IAC 8-4-3 Petroleum Liquid Storage Facilities

Tanks TK-41, TK-42, 503, 504 and 505 have capacities greater than 39,000 gallons and a true vapor pressure greater than 1.52 psi therefore, 326 IAC 8-4-3 applies to these tanks. Tanks TK-43, TK-44 and TK-45 have capacities less than 39,000 gallons therefore, 326 IAC 8-4-3 does not apply to these tanks. Tanks 501, 502, and 506 have a true vapor pressure of less than 1.52 therefore, 326 IAC 8-4-3 does not apply to these tanks.

- (a) No owner or operator of an affected fixed roof tank shall permit use of such facility unless:
- (1) The facility has been retrofitted 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 retrofitted with equally effective alternative control which has been approved.
 - (2) The facility is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials.
 - (3) All openings, except stub drains, are equipped with covers, lids, or seals such that:
 - (A) The cover, lid, or seal is in the closed position at all times except when in actual use;
 - (B) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports;
 - (C) 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.

Conclusion

The operation of this petroleum processing facility shall be subject to the conditions of the attached Registration 069-12935-00042.

§ 60.40c

paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low nitrogen oxide (NO_x) technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a stack test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO₂ and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[52 FR 47842, Dec. 16, 1987, as amended at 54 FR 51820, 51825, Dec. 18, 1989; 60 FR 28062, May 30, 1995; 61 FR 14031, Mar. 29, 1996; 62 FR 52641, Oct. 8, 1997; 63 FR 49455, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999; 65 FR 13243, Mar. 13, 2000]

40 CFR Ch. I (7-1-01 Edition)

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 55 FR 37683, Sept. 12, 1990, 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 Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/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 which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 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 ch a separate

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source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials in ASTM D388-77, "Standard Specification for Classification of Coals by Rank" (incorporated by reference—see § 60.17); coal refuse; and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are 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 com-

bustion 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 D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see § 60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO₂) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed 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

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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 D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (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 SO₂ emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] 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 reac-

tion 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 D396-78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (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 SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: (1) cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction); nor (2) cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO₂ reduction requirement specified in this paragraph and 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 initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is fired with coal refuse, the affected facility is 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 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility

any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 million Btu/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 of this part, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the

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atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/million Btu) 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 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate 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 million Btu/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:

$$E_s = (K_a H_a + K_b H_b + K_c H_c) / (H_a + H_b + H_c)$$

where:

E_s is the SO₂ emission limit, expressed in ng/J or lb/million Btu heat input,

K_a is 520 ng/J (1.2 lb/million Btu),

K_b is 260 ng/J (0.60 lb/million Btu),

K_c is 215 ng/J (0.50 lb/million Btu),

H_a is the 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) [million Btu]

H_b is the heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (million Btu)

H_c is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement

under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), 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)(1), (2), or (3), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) 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.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.43c Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or required to be completed

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under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 million Btu/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/million Btu) 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/million Btu) 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 of this part, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/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/million Btu) 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/million Btu) 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 of this part, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input ca-

capacity of 8.7 MW (30 million Btu/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.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 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 in § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the 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) and § 60.8, compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit

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operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{hoO}) is used in Equation 19-19 of Method 19 to compute the adjusted E_{ao} (E_{aoO}). The E_{hoO} is computed using the following formula:

$$E_{hoO} = [E_{ho} - E_w(1 - X_k)] / X_k$$

where:

E_{hoO} is the adjusted E_{ho}, ng/J (lb/million Btu)

E_{ho} is the hourly SO₂ emission rate, ng/J (lb/million Btu)

E_w is the SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9, ng/J (lb/million Btu). 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 is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(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.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO₂ 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 SO₂ emission rate is computed using the following formula:

$$\%P_s = 100(1 - \%R_g/100)(1 - \%R_f/100)$$

where

%P_s is the percent of potential SO₂ emission rate, in percent

%R_g is the SO₂ removal efficiency of the control device as determined by Method 19, in percent

%R_f is the SO₂ removal efficiency of fuel pretreatment as determined by Method 19, in percent

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the %P_s, an adjusted %R_g (%R_{gO}) is computed from E_{aoO} from paragraph (e)(1) of this section and an adjusted average SO₂ inlet rate (E_{aiO}) using the following formula:

$$\%R_{gO} = 100 [1.0 - E_{aoO}/E_{aiO}]$$

where:

%R_{gO} is the adjusted %R_g, in percent

E_{aoO} is the adjusted E_{ao}, ng/J (lb/million Btu)

E_{aiO} is the adjusted average SO₂ inlet rate, ng/J (lb/million Btu)

(ii) To compute E_{aiO}, an adjusted hourly SO₂ inlet rate (E_{hiO}) is used. The E_{hiO} is computed using the following formula:

$$E_{hiO} = [E_{hi} - E_w(1 - X_k)] / X_k$$

where:

E_{hiO} is the adjusted E_{hi}, ng/J (lb/million Btu)

E_{hi} is the hourly SO₂ inlet rate, ng/J (lb/million Btu)

E_w is the SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million Btu). 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 is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling

and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under § 60.48c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO₂ standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P_s and E_{h_o} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P_s or E_{h_o} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 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.

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3 shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.

(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 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 may be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B 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 Method 5B, 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 or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing

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the duct at the same sampling location.

(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million Btu) heat input shall be determined using:

(i) The oxygen or carbon dioxide 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 (appendix A).

(8) Method 9 (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.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.46c Emission monitoring for sulfur dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO₂ emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under

§60.42c shall measure SO₂ concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (appendix F).

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average

SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B 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. Method 19 provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and carbon dioxide 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 (appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 or Methods 6C and 3A are suitable measurement techniques. If Method 6B 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 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under §60.48c(f) (1), (2), or (3), 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.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, residual 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.

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(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.

[55 FR 37683, Sept. 12, 1990, as amended at 65 FR 61753, Oct. 17, 2000]

§ 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, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B.

(c) The owner or operator of each coal-fired, residual 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 which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.43c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (nj/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (oxygen or carbon dioxide) 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.

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(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 (appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(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), or (3) 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; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c.

(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 de-

termine 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.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(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.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000]

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging

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(2) Each owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112a (a)(3) and (b).

[45 FR 23379, Apr. 4, 1980]

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 paragraphs (b), (c), and (d) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 40 cubic meters (m³) that is used to store volatile organic liquids (VOL's) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) Except as specified in paragraphs (a) and (b) of § 60.116b, storage vessels with design capacity less than 75 m³ are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(c) Except as specified in paragraphs (a) and (b) of § 60.116b, vessels either with a capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure less than 15.0 kPa are exempt from the General Provisions (part 60, subpart A) and from the provisions of this subpart.

(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, rail-cars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m³ used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 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:

(a) *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.

(b) *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.

(c) *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.

(d) *Fill* means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

(e) *Gasoline service station* means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

(f) *Maximum true vapor pressure* means the equilibrium partial pressure exerted by 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

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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 Method D2879-83 (incorporated by reference—see § 60.17);

(4) Any other method approved by the Administrator.

(g) *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 (incorporated by reference—see § 60.17).

(h) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(i) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

(j) *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; or

(2) Subsurface caverns or porous rock reservoirs.

(k) *Volatile organic liquid (VOL)* means any organic liquid which can emit volatile organic compounds into the atmosphere except those VOL's that emit only those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone. These compounds are identified in EPA statements on ozone abatement policy for SIP revisions (42 FR 35314, 44 FR 32042, 45 FR 32424, and 45 FR 48941).

(l) *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

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treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be

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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.

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(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 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit

shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) 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

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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 Cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm² per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension

request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

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(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 speci-

fied in the general control device requirements, § 60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(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.

§ 60.115b

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(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 § 60.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 60.112b(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. Each storage vessel with a design capacity less than 75 m³ is subject to no provision of this subpart other than those required by this paragraph.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage

temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the 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 Method D2879-83 (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.

§ 60.117b

(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 Method D2879-83 (incorporated by reference—see §60.17); or

(ii) ASTM Method D323-82 (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 specifications of §60.112b is exempt from the requirements of paragraphs (c) and (d) of this section.

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§ 60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Subpart L—Standards of Performance for Secondary Lead Smelters

§ 60.120 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: Pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

[42 FR 37937, July 25, 1977]

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§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Reverberatory furnace* includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) *Secondary lead smelter* means any facility producing lead from a leadbearing scrap material by smelting to the metallic form.

(c) *Lead* means elemental lead or alloys in which the predominant component is lead.

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974]

§ 60.122 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any pot furnace any gases which exhibit 10 percent opacity or greater.

[39 FR 9317, Mar. 8, 1974, as amended at 40 FR 46259, Oct. 6, 1975]

§ 60.123 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 standards in §60.122 as follows:

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification: T-41
City: Huntington
State: Indiana
Company: Gladieux Processing LLC
Type of Tank: Vertical Fixed Roof Tank
Description: Tank 41

Tank Dimensions

Shell Height (ft): 36.00
Diameter (ft): 14.00
Liquid Height (ft): 34.00
Avg. Liquid Height (ft): 34.00
Volume (gallons): 39,152.37
Turnovers: 20.43
Net Throughput (gal/yr): 800,000.00
Is Tank Heated (y/n): N

Paint Characteristics

Shell Color/Shade: Gray/Light
Shell Condition: Good
Roof Color/Shade: Gray/Light
Roof Condition: Good

Roof Characteristics

Type: Cone
Height (ft): 2.00
Slope (ft/ft) (Cone Roof): 0.29

Breather Vent Settings

Vacuum Settings (psig): -0.03
Pressure Settings (psig): 0.03

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0

Emissions Report - Summary Format

Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf Temperatures (deg F)			Liquid Bulk Temp. (deg F)		Vapor Pressures (psia)		Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.	Avg.	Max.	Avg.	Max.					
Gasoline (RVP 8)	All	58.05	50.59	67.51	54.50	3.9676	3.3383	4.6894	68.0000			92.00	Option 4: RVP=8, ASTM Slope=3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)		
	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 8)	5,138.98	883.56	6,022.54

T-42
Gladioux Processing LLC

Vertical Fixed Roof Tank
Huntington, Indiana

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification: T-42
City: Huntington
State: Indiana
Company: Gladioux Processing LLC
Type of Tank: Vertical Fixed Roof Tank
Description: Tank 42

Tank Dimensions

Shell Height (ft): 36.00
Diameter (ft): 14.00
Liquid Height (ft): 34.00
Avg. Liquid Height (ft): 34.00
Volume (gallons): 39,152.37
Turnovers: 20.43
Net Throughput (gal/yr): 800,000.00
Is Tank Heated (y/n): N

Paint Characteristics

Shell Color/Shade: Gray/Light
Shell Condition: Good
Roof Color/Shade: Gray/Light
Roof Condition: Good

Roof Characteristics

Type: Cone
Height (ft): 2.00
Slope (ft/ft) (Cone Roof): 0.29

Breather Vent Settings

Vacuum Settings (psig): -0.03
Pressure Settings (psig): 0.03

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

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TANKS 4.0

Emissions Report - Summary Format

Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)		Vapor Pressures (psia)		Vapor Mol Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg	Min.	Max.	Avg.	Min.	Max.						
Gasoline (RVP 8)	All	59.05	50.59	67.51	54.50	3.9676	3.3383	4.6894	68.0000			92.00	Option 4: RVP=8, ASTM Slope=3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses (lbs)		
	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 8)	5,138.98	883.56	6,022.54

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification:	T-43
City:	Huntington
State:	Indiana
Company:	Gladieux Processing LLC
Type of Tank:	Vertical Fixed Roof Tank
Description:	Tank 43

Tank Dimensions

Shell Height (ft):	29.00
Diameter (ft):	12.00
Liquid Height (ft):	28.00
Avg. Liquid Height (ft):	28.00
Volume (gallons):	23,688.83
Turnovers:	3.38
Net Throughput (gal/yr):	80,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition:	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft):	1.00
Slope (ft/ft) (Cone Roof):	0.17

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0

Emissions Report - Summary Format

Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)		Vapor Pressures (psia)			Vapor Mol. Weight		Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg	Min.	Max.	Avg	Min.	Max.	Min.	Max.	Min.	Max.	Mol. Weight			
Residual oil no. 6	All	59.05	50.59	67.51	54.50	0.0000	0.0000	0.0001	190.0000					387.00	Option 5: A=10.104, B=10475

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)			Total Emissions
	Working Loss	Breathing Loss		
Residual oil no. 6	0.02	0.00		0.02

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification: T-44
City: Huntington
State: Indiana
Company: Gladieux Processing LLC
Type of Tank: Vertical Fixed Roof Tank
Description: Tank 44

Tank Dimensions

Shell Height (ft): 32.00
Diameter (ft): 11.00
Liquid Height (ft): 30.00
Avg. Liquid Height (ft): 30.00
Volume (gallons): 21,327.00
Turnovers: 56.27
Net Throughput (gal/yr): 1,200,000.00
Is Tank Heated (y/n): N

Paint Characteristics

Shell Color/Shade: Gray/Light
Shell Condition: Good
Roof Color/Shade: Gray/Light
Roof Condition: Good

Roof Characteristics

Type: Cone
Height (ft): 2.00
Slope (ft/ft) (Cone Roof): 0.36

Breather Vent Settings

Vacuum Settings (psig): -0.03
Pressure Settings (psig): 0.03

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)		Vapor Pressures (psia)		Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg	Min.	Max.	Avg.	Min.	Max.						
Jet naphtha (JP-4)	All	59.05	50.59	67.51	54.50	1.2422	1.0325	1.4857	80.0000			120.00	Option 5: A=1.368, B=5784.3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)		
	Working Loss	Breathing Loss	Total Emissions
Jet naphtha (JP-4)	1,987.09	133.87	2,120.96

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification
User Identification: T-45
City: Huntington
State: Indiana
Company: Gladieux Processing LLC
Type of Tank: Vertical Fixed Roof Tank
Description: Tank 45

Tank Dimensions
Shell Height (ft): 30.00
Diameter (ft): 10.50
Liquid Height (ft): 28.00
Avg. Liquid Height (ft): 28.00
Volume (gallons): 18,136.76
Turnovers: 24.81
Net Throughput (gal/yr): 450,000.00
Is Tank Heated (y/n): N

Paint Characteristics
Shell Color/Shade: Gray/Light
Shell Condition: Good
Roof Color/Shade: Gray/Light
Roof Condition: Good

Roof Characteristics
Type: Cone
Height (ft): 2.00
Slope (ft/ft) (Cone Roof): 0.38

Breather Vent Settings
Vacuum Settings (psig): -0.03
Pressure Settings (psig): 0.03

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)		Vapor Pressures (psia)		Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg	Min.	Max.	Avg.	Min.	Max.						
Gasoline (RVP 8)	All	59.05	50.59	67.51	54.50	3.9676	3.3383	4.6894	68.0000			92.00	Option 4: RVP=8, ASTM Slope=3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Working Loss	Losses (lbs)		Total Emissions
		Breathing Loss		
Gasoline (RVP 8)	2,890.68	497.00	3,387.68	

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TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification:	501
City:	Huntington
State:	Indiana
Company:	Gladieux Trading & Marketing Co., L.P.
Type of Tank: —	Vertical Fixed Roof Tank
Description:	Gladieux Trading

Tank Dimensions

Shell Height (ft):	48.00
Diameter (ft):	90.00
Liquid Height (ft):	44.00
Avg. Liquid Height (ft):	44.00
Volume (gallons):	2,093,923.32
Turnovers:	9.74
Net Throughput (gal/yr):	20,400,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft):	2.00
Slope (ft/ft) (Cone Roof):	0.04

Breather Vent Settings

Vacuum Settings (psig):	0.00
Pressure Settings (psig):	0.00

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
		54.01	48.91	59.11	52.28	0.0053	0.0045	0.0063	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)		Total Emissions
	Working Loss	Breathing Loss	
Distillate fuel oil no. 2	335.18	53.97	389.15

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification: 502
 City: Huntington
 State: Indiana
 Company: Gladieux Trading & Marketing Co., L.P.
 Type of Tank: Internal Floating Roof Tank
 Description:

Tank Dimensions

Diameter (ft): 40.00
 Volume (gallons): 60,319.00
 Turnovers: 78.50
 Self Supp. Roof? (y/n): N
 No. of Columns: 1.00
 Eff. Col. Diam. (ft): 1.00

Paint Characteristics

Internal Shell Condition: Light Rust
 Shell Color/Shade: White/White
 Shell Condition: Good
 Roof Color/Shade: White/White
 Roof Condition: Good

Rim-Seal System

Primary Seal: Liquid-mounted
 Secondary Seal: Rim-mounted

Deck Characteristics

Deck Fitting Category: Detail
 Deck Type: Bolted
 Construction: Panel
 Deck Seam: Panel: 5 x 7.5 Ft
 Deck Seam Len. (ft): 414.69

Deck Fitting/Status

	Quantity
Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	
Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask.	1
Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed	1
Roof Leg or Hanger Well/Adjustable	12

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open	1
Stub Drain (1-in. Diameter)/	13
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
		54.01	48.91	59.11	52.28	0.0067	N/A	N/A	130.0000			162.00	Option 5: A=12.39, B=8933

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)				Total Emissions
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	
Jet kerosene	0.18	28.60	4.61	1.13	34.53

TANKS 4.0 Emissions Report - Summary Format Tank Identification and Physical Characteristics

Identification

User Identification: 503
 City: Huntington
 State: Indiana
 Company: Gladieux Trading & Marketing Co., L.P.
 Type of Tank: Internal Floating Roof Tank
 Description:

Tank Dimensions

Diameter (ft): 60.00
 Volume (gallons): 135,717.00
 Turnovers: 51.36
 Self Supp. Roof? (y/n): Y
 No. of Columns: 0.00
 Eff. Col. Diam. (ft): 0.00

Paint Characteristics

Internal Shell Condition: Light Rust
 Shell Color/Shade: White/White
 Shell Condition: Good
 Roof Color/Shade: White/White
 Roof Condition: Good

Rim-Seal System

Primary Seal: Liquid-mounted
 Secondary Seal: Rim-mounted

Deck Characteristics

Deck Fitting Category: Typical
 Deck Type: Welded

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	
Roof Leg or Hanger Well/Adjustable	
Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open	
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask	

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Gasoline (RVP 13)	All	54.01	48.91	59.11	52.28	6.2041	N/A	N/A	62.0000			92.00	Option 4: RVP=13, ASTM Slope=3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)				Total Emissions
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	
Gasoline (RVP 13)	157.28	21.91	1,769.42	0.00	1,948.61

TANKS 4.0 Emissions Report - Summary Format Tank Identification and Physical Characteristics

Identification

User Identification: 504
 City: Huntington
 State: Indiana
 Company: Gladioux Trading & Marketing Co., L.P.
 Type of Tank: External Floating Roof Tank
 Description:

Tank Dimensions

Diameter (ft): 90.00
 Volume (gallons): 305,363.00
 Turnovers: 91.69

Paint Characteristics

Internal Shell Condition: Light Rust
 Shell Color/Shade: White/White
 Shell Condition: Good

Roof Characteristics

Type: Double Deck
 Fitting Category: Typical

Tank Construction and Rim-Seal System

Construction: Welded
 Primary Seal: Liquid-mounted
 Secondary Seal: Rim-mounted

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Unslotted Guide-Pole Well/Ungasketed Sliding Cover	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Roof Drain (3-in. Diameter)/Open	1
Roof Leg (3-in. Diameter)/Adjustable, Double-Deck Roofs	20

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0 Emissions Report - Summary Format Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
		54.01	48.91			2.7501	N/A				145.49		
						0.0053	N/A		0.7200	0.0023	188.00	Option 5: A=12.101, B=8907	
						6.2041	N/A		0.2800	0.9977	92.00	Option 4: RVP=13, ASTM Slope=3	

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)				Total Emissions
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	
Transmix	440.76	69.20	7,587.46	0.00	8,097.43
Distillate fuel oil no. 2	0.99	49.83	17.09	0.00	67.91
Gasoline (RVP 13)	439.77	19.38	7,570.37	0.00	8,029.52

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification: 505
 City: Huntington
 State: Indiana
 Company: Gladieux Trading & Marketing Co., L.P.
 Type of Tank: Internal Floating Roof Tank
 Description:

Tank Dimensions

Diameter (ft): 40.00
 Volume (gallons): 60,319.00
 Turnovers: 51.43
 Self Supp. Roof? (y/n): Y
 No. of Columns: 0.00
 Eff. Col. Diam. (ft): 0.00

Paint Characteristics

Internal Shell Condition: Light Rust
 Shell Color/Shade: White/White
 Shell Condition: Good
 Roof Color/Shade: White/White
 Roof Condition: Good

Rim-Seal System

Primary Seal: Liquid-mounted
 Secondary Seal: Rim-mounted

Deck Characteristics

Deck Fitting Category: Typical
 Deck Type: Welded

Deck Fitting/Status

	Quantity
Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	1
Roof Leg or Hanger Well/Adjustable	12
Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open	1
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1

Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Gasoline (RVP 13)	All	54.01	48.91	59.11	52.28	6.2041	N/A	N/A	62.0000			92.00	Option 4: RVP=13, ASTM Slope=3

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)				Total Emissions
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	
Gasoline (RVP 13)	104.85	14.63	1,424.27	0.00	1,543.75

TANKS 4.0

Emissions Report - Summary Format

Tank Identification and Physical Characteristics

Identification

User Identification: 506
 City: Huntington
 State: Indiana
 Company: Gladioux Trading & Marketing Co., L.P.
 Type of Tank: Internal Floating Roof Tank
 Description:

Tank Dimensions

Diameter (ft): 60.00
 Volume (gallons): 135,717.00
 Turnovers: 78.38
 Self Supp. Roof? (y/n): N
 No. of Columns: 1.00
 Eff. Col. Diam. (ft): 1.00

Paint Characteristics

Internal Shell Condition: Light Rust
 Shell Color/Shade: White/White
 Shell Condition: Good
 Roof Color/Shade: White/White
 Roof Condition: Good

Rim-Seal System

Primary Seal: Liquid-mounted
 Secondary Seal: Rim-mounted

Deck Characteristics

Deck Fitting Category: Typical
 Deck Type: Bolted
 Construction: Panel
 Deck Seam: Panel: 5 x 7.5 Ft
 Deck Seam Len. (ft): 933.05

Deck Fitting/Status

	Quantity
Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	1
Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask.	1
Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed	1
Roof Leg or Hanger Well/Adjustable	17

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open
Stub Drain (1-in. Diameter)/
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.

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Meteorological Data used in Emissions Calculations: Indianapolis, Indiana (Avg Atmospheric Pressure = 14.33 psia)

TANKS 4.0 Emissions Report - Summary Format Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F)			Liquid Bulk Temp. (deg F)	Vapor Pressures (psia)			Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Jet kerosene	All	54.01	48.91	59.11	52.28	0.0067	N/A	N/A	130.0000			162.00	Option 5: A=12.39, B=8933

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Annual Emissions Report

Components	Losses(lbs)				Total Emissions
	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	
Jet kerosene	0.28	42.49	5.51	2.54	50.82